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BEFORE THE ARIZONA CORPORATION COMMISSION

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JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

Arizona Corporation Commission
DOCKETED
APR 04 2005
DOCKETED BY

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A RATE INCREASE

DOCKET NO.E-01773A-04-0528

IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A RATE INCREASE.

DOCKET NO. E-04100A-04-0527

NOTICE OF FILING SURREBUTTAL TESTIMONY

In regard to Arizona Electric Power Cooperative, Inc., the Utilities Division ("Staff") of the Arizona Corporation Commission provides notice of filing the Surrebuttal Testimony of Crystal S. Brown, Alejandro Ramirez, and Barbara Keene.

In regard to Southwest Transmission Cooperative, Inc., Staff provides notice of filing the Surrebuttal Testimony of Crystal S. Brown, Alejandro Ramirez, and Erin Casper.

RESPECTFULLY SUBMITTED this 4th day of April 2005.

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Diane M. Targovnik
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The original and fifteen (15) copies of the foregoing were filed this 4th day of April 2005 with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

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Secretary to Tim Sabo

SURREBUTTAL

TESTIMONY

OF

CRYSTAL S. BROWN

ALEJANDRO RAMIREZ

ERIN CASPER

DOCKET NO E-04100A-0528

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN

APRIL 4, 2005

BROWN

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF	)	DOCKET NO. E-01773A-04-0528
ARIZONA ELECTRIC POWER COOPERATIVE,	)	
INC. FOR A HEARING TO DETERMINE THE	)	
FAIR VALUE OF ITS PROPERTY FOR	)	
RATEMAKING PURPOSES, TO FIX A JUST	)	
AND REASONABLE RETURN THEREON AND	)	
TO APPROVE RATES DESIGNED TO DEVELOP	)	
SUCH RETURN	)	

SURREBUTTAL TESTIMONY OF

CRYSTAL S. BROWN

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 4, 2005

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SCHEDULES

EXECUTIVE SUMMARY
ARIZONA ELECTRIC POWER COOPERATIVE, INC.
DOCKET NO. E-01773A-04-0528

Ms. Brown's surrebuttal testimony presents Staff's response to Arizona Electric Power Cooperative, Inc.'s ("AEPCO" or "Cooperative") rebuttal testimony regarding the revenue and expense annualization adjustment, the Tracker Mechanism (Base Cost of Power) adjustment, and the overhaul accrual expense adjustment. Also, Staff responds to the Cooperative's comments on the redacted legal invoices, food and similar expenses, jurisdictional separation, the Sulphur Springs Partial Requirements Capacity and Energy Agreement, and the revised depreciations rates.

INTRODUCTION

Q. Please state your name.

A. My name is Crystal S. Brown.

Q. Are you the same Crystal S. Brown who previously submitted pre-filed testimony in this docket?

A. Yes, I am.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond, on behalf of the Utilities Division ("Staff"), to the rebuttal testimony of Arizona Electric Power Cooperative, Inc.'s ("AEPCO" or "Cooperative") rebuttal testimony regarding Staff's Revenue and Expense Annualization adjustment, Overhaul Accrual Expense adjustment, and the Tracker Mechanism (Base Power Cost) adjustment. Also, Staff responds to the Cooperative's comments on the redacted legal invoices, food and similar expenses, jurisdictional separation, the Sulphur Springs Partial Requirements Capacity and Energy Agreement, and the depreciation rates.

SUMMARY OF COOPERATIVE'S REBUTTAL TESTIMONY

Q. Please summarize AEPCO's rebuttal testimony.

A. AEPCO's rebuttal testimony raises concerns about:

1. Staff's inclusion of Mohave Electric Cooperative, Inc.'s ("Mohave") customer growth in the revenue and expense annualization calculations;
2. Staff's use of historical overhaul expense that does not reflect the $1.6 million in overhaul expense expected to be incurred when a new gas turbine is overhauled;

3. Staff's classification of the $250,000 pro forma adjustment as a reduction in the purchased power energy costs of the Public Service Company of New Mexico; Staff's inclusion of $2,215,834 in margins associated with economy energy sales, and; Staff's inclusion of certain purchased capacity charges and associated wheeling expenses for the Panda Gila River purchased power agreement for which Mohave elected not to participate.
4. The Cooperative also comments on the redacted legal invoices, food and similar expenses, jurisdictional separation, Sulphur Springs Partial Requirements Capacity and Energy Agreement, and the revised depreciation rates.

REVENUE AND EXPENSE ANNUALIZATIONS

Q. What is AEPCO's rebuttal response to Staff's Operating Income Adjustment No. 2, "Revenue and Expense Annualizations"?

A. AEPCO agrees with Staff's annualization calculation except for the inclusion of customer growth for Mohave. The Cooperative indicated that since Mohave is a partial requirements customer, Mohave's customer growth does not result in increased revenues and expenses. AEPCO removed the customer growth for Mohave and calculated a 1.61 percent annualization factor.

Q. Does Staff agree that Mohave should be removed from the calculation of the annualization factor and AEPCO's 1.61 percent growth factor?

A. Yes.

Q. Does Staff agree that its annualization adjustment to operating revenue was overstated by $336,455 as proposed by the Cooperative?

A. No. The Cooperative's $336,455 adjustment to revenue is calculated by multiplying $56,092,646 times 1.67 percent rather than its 1.61 percent growth factor. Using a 1.61 percent growth factor, Staff calculated that its annualization adjustment to operating revenue was overstated by $368,421, a difference of $31,966.

Q. Does Staff agree that its annualization adjustment to operating expense was overstated by $5,658 as stated by the Cooperative?

A. Yes.

Q. What is Staff recommending?

A. Staff recommends decreasing Test Year operating revenues by $368,421 and operating expenses by $5,658 as shown on Surrebuttal Schedules CSB-4 and CSB-5.

TRACKER MECHANISM (BASE POWER COST)

Q. What is AEPCO's rebuttal response to Staff's Operating Income Adjustment No. 4, "Tracker Mechanism (Base Power Cost)"?

A. AEPCO accepts Staff's adjustment with the exception of (1) Staff's classification of the $250,000 pro forma adjustment as a reduction in the purchased power energy costs of the Public Service Company of New Mexico ("PNM") (2) Staff's inclusion of $2,215,834 in margins associated with economy energy sales, and (3) Staff's inclusion of certain purchased capacity charges and associated wheeling expenses for the Panda Gila River purchased power agreement for which Mohave elected not to participate.

Q. Please discuss AEPCO's rebuttal response to the $250,000 adjustment.

A. The Cooperative stated that Staff's classification of the $250,000 pro forma adjustment as a reduction in the purchased power energy costs of the Public Service Company of New Mexico contract is incorrect. The $250,000 pertains to the payment for a 2MW contract demand reduction in the AEPCO/PNM contract. Therefore, the $250,000 should have been deducted from purchased power demand costs rather than purchased power energy costs.

Q. Does Staff agree that the $250,000 should have been deducted from purchased power demand costs rather than purchased power energy costs?

A. Yes.

Q. What is Staff recommending?

A. Staff recommends reclassifying the $250,000 reduction from purchased power energy costs to purchased power demand costs as shown on Surrebuttal Schedules CSB-4 and CSB-6.

Q. Please discuss AEPCO's rebuttal response to Staff's inclusion of $2,215,834 in margins associated with economy energy sales.

A. The Cooperative removed the $2,215,834 in margins associated with economy energy sales primarily because it claims the credit would result in a double recovery of those margins.

Q. Does Staff agree that the $2,215,834 in margins associated with economy energy sales should be removed?

A. As discussed in the testimony of Ms. Barbara Keene, Staff does not agree that they should be removed.

Q. What is Staff recommending?

A. Staff continues to recommend inclusion of the $2,215,834 in margins associated with economy energy sales.

Q. Please discuss AEPCO's rebuttal response to the Staff's inclusion of certain purchased capacity charges and associated wheeling expenses related to Mohave.

A. Mohave did not participate in the Panda Gila River purchased power agreement and avoided certain purchased capacity charges and associated wheeling expenses. The Cooperative removed the costs from Mohave's fixed charge and operations and maintenance rate and made a corresponding adjustment to remove the costs from Mohave's base cost of power.

Q. Does the Cooperative's rebuttal proposal affect Staff's Operating Income Adjustment No. 4, "Tracker Mechanism (Base Power Cost)" ?

A. No, it does not. Staff's adjustment pertains to Test Year revenues and expenses which includes Mohave as well as full requirements customers. Staff calculations were not developed to determine the base power cost, only the total cost. Consequently, the breakout of Mohave from the full requirements customers for the purposes of developing separate base rates has no effect on Staff's adjustment.

Q. What is Staff recommending?

A. Staff continues to recommend the Tracker Mechanism (Base Power Cost) adjustments shown on Surrebuttal Schedule CSB-6.

OPERATING INCOME ADJUSTMENT NO. 5 – OVERHAUL ACCRUAL EXPENSE

Q. What is AEPCO's rebuttal response to Staff's Operating Income Adjustment No. 5, "Overhaul Accrual Expense"?

A. The Cooperative accepted Staff's adjustment with the exception of Staff's use of historical data for a new gas turbine that went into service in 2002. Staff's overhaul accrual expense calculation does not reflect the $1.6 million in overhaul expense expected to be incurred when the new gas turbine is overhauled.

Q. Does Staff agree that the overhaul accrual expense calculation should include an estimated overhaul expense for gas turbine no. 4 in the absence of historical data?

A. Yes.

Q. What is Staff recommending?

A. Staff recommends increasing overhaul accrual expense as shown on Surrebuttal Schedules CSB-4 and CSB-7.

REDACTED LEGAL INVOICES AND MINUTES OF THE BOARD OF DIRECTORS

Q. What is AEPCO's rebuttal response to Staff's adjustment to disallow costs related to certain legal invoices and minutes of the board of directors?

A. AEPCO accepted Staff's adjustment. Although Staff does agree with the Cooperative's other statements on this matter, there is no further need to comment on the matter beyond what Staff stated in its direct testimony.

FOOD AND OTHER EXPENSE

Q. What is AEPCO's rebuttal response to Staff's adjustment to disallow costs related to food and other similar expenses?

A. AEPCO accepted Staff's adjustment. However, the Cooperative claims that many of the expenses, such as food for the Member Meetings, training, and recruitment were necessary for safe, reliable, and adequate service.

Q. Are food, entertainment, and similar expenses needed in the provision of safe, reliable service?

A. No, they are non-essential costs for the provision of service.

Q. How are customers affected when non-essential costs are included in rates?

A. Customers are unnecessarily charged higher rates when non-essential costs are built into rates. If this occurs, a portion of each customer's bill would pay for the non-essential costs. These non-essential costs could be reduced or eliminated and the customers' service would not be affected.

JURISDICTIONAL SEPARATION

Q. What is AEPCO's rebuttal response to Staff's recommendation that it "separate nonjurisdictional properties, revenues and expenses" in compliance with the Arizona Administrative Code?

A. AEPCO did not accept Staff's recommendation because (1) the Commission had never required the Cooperative to jurisdictionally separate the rate base and expenses for its California customer (i.e., Anza) and (2) the benefit derived from such compliance would not justify the cost.

Q. Is the Cooperative's argument that it has never been required to perform a cost of service study for Anza since 1979 justification for not jurisdictionally separating rate base and expenses?

A. No. Previous non-filing of jurisdictionally separated data is not justification for continued non-filing of jurisdictionally separated data. The Cooperative's response indicates that the Cooperative does not know nor has ever known (based upon a study) what the rate base and expense elements are for Anza.

Q. Has the Cooperative supported its assertion that the benefits of the jurisdictional separations requirements would exceed the costs?

A. No. The Cooperative does not know the benefits. The benefits cannot be determined until the jurisdictional separation is performed.

Q. Can Staff provide an example of the potential inequity that is presented by absence of jurisdictional separations.

A. Hypothetically, the cost to serve a customer that represents 2 percent of revenues could be 10 percent of costs. The result in such a case is a substantive subsidization for this customer. Staff cannot know if this situation is occurring unless the Cooperative provides jurisdictionally separated data.

Q. Does Staff believe that it would be cost prohibitive to jurisdictionally separate the data?

A. No, because smaller cooperatives have provided jurisdictionally separated data. In addition, other smaller cooperatives have also provided cost of service studies that allocate rate base, revenue, and expenses by customer class. Further, once the framework/methodology has been established, the process to update the studies should be relatively straightforward.

Q. What is the benefit of requiring jurisdictionally separated data?

A. The information would assist in the pricing out of contracts and development of cost-based rates.

Q. What is Staff recommending?

A. Staff continues to recommend that the Cooperative jurisdictionally separate the data in all subsequent rate filings.

SULPHUR SPRINGS PARTIAL REQUIREMENTS CAPACITY AND ENERGY AGREEMENT

Q. Please discuss the Sulphur Springs Partial Requirements Capacity and Energy Agreement.

A. The Cooperative is currently in negotiations with Sulphur Springs pertaining to a Partial Requirements Capacity and Energy Agreement.

Q. Is the agreement finalized?

A. No, it is not.

Q. What is Staff recommending?

A. Since the impact of the agreement cannot be determined and it is not known and measurable, it should not be considered in this proceeding. As with any other utility activity, AEPCO can assess its regulatory alternatives once the agreement is finalized.

DEPRECIATION RATES

Q. Does Staff recommend adoption of the rates for two of AEPCO's generating units discussed in the direct testimony of Mr. Dirk Minson[1]?

A. Yes. Staff witness, Jerry Smith, has reviewed the depreciation rates and recommends adoption.

SUMMARY OF STAFF'S SURREBUTTAL REVENUE POSITION

Q. Please summarize Staff's recommended revenue.

A. Staff recommends total annual operating revenue of no less than that proposed by AEPCO, which is $148,397,723, an increase of $9,477,998, or 6.82 percent, over Staff adjusted Test Year revenues of $138,919,725. The recommended revenue would produce an operating margin of $19,903,441 for a 10.50 percent rate of return on the original cost and fair value rate base of $189,637,810 to provide a 1.50 times interest earned ratio ("TIER") and a 0.99 debt service coverage ratio ("DSC").

Q. Does this conclude your surrebutal testimony?

A. Yes, it does.

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[1] Page 10, beginning at line 24

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Surrebuttal Schedule CSB-1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	[A] STAFF DIRECT ORIGINAL COST	[B] COOPERATIVE REBUTTAL ORIGINAL COST	[C] STAFF SURREBUTTAL ORIGINAL COST
1	Adjusted Operating Income (Loss)	$ 10,981,774	$ 10,457,408	$ 10,425,443
2	Depreciation and Amortization	$ 7,539,289	$ 7,539,289	$ 7,539,289
3	Income Tax Expense	-	-	-
4	Long-term Interest Expense	$ 13,313,164	$ 13,313,164	$ 13,313,164
5	Principal Repayment	$ 14,360,494	$ 14,360,494	$ 14,360,494
6a	**Recommended Increase in Operating Revenue**	**$ 6,773,320**	**$ 9,446,032**	**$ 9,477,998**
6b	**Percent Increase (Line 6a / Line 7) - Per Staff**	**4.86%**	**6.80%**	**6.82%**
6c	Percent Increase (Line 6a / $85,685,624) - Per Coop	N/A	11.02%	N/A
7	Adjusted Test Year Operating Revenue	$ 139,288,146	$ 138,951,691	$ 138,919,725
8	**Recommended Annual Operating Revenue**	$ 146,061,466	**$ 148,397,723**	**$ 148,397,723**
9a	**Recommended Operating Margin Before Interest**	$ 17,755,094	**$ 19,903,440**	**$ 19,903,441**
9b	Recommended Net Margins(Loss) After Interest	$ 4,099,540	$ 6,247,886	$ 6,247,887
9c	Recommended Net Margins	$ 6,061,991	$ 8,210,337	$ 8,210,338
10a	**Recommended Operating TIER (L3+L9)/L4 - Per Staff**	**1.33**	**1.50**	**1.50**
10b	Recommended Net TIER (L4+L9c)/L4 - Per Coop	N/A	1.62	N/A
11a	**Recommended DSC (L2+L3+L9)/(L4+L5) - Per Staff**	**0.91**	**0.99**	**0.99**
11b	Recommended DSC (L2+L4+L9c)/(L4+L5) - Per Coop	N/A	1.05	N/A
12	**Adjusted Rate Base**	$ 189,637,810	**$ 189,637,810**	**$ 189,637,810**
13	Rate of Return (L9a / L12)	9.36%	10.50%	10.50%

References:
Column [A]: Brown, Direct Testimony, Schedule CSB-1
Column [B]: Pierson, Rebuttal Testimony, Exhibit GEP-2
Column [C]: Surrebuttal Testimony

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Surrebuttal Schedule CSB-2

RATE BASE - ORIGINAL COST

LINE NO.		[A] STAFF DIRECT	[B] ADJUSTMENTS	[C] STAFF SURREBUTTAL
1	Plant in Service	$ 377,675,263	$ -	$ 377,675,263
2	Less: Acc Depreciation & Amortization	(185,936,636)	-	(185,936,636)
3	Net Plant in Service	$ 191,738,627	$ -	$ 191,738,627
	LESS:			
4	Advances in Aid of Construction (AIAC)	$ -	$ -	$ -
5	Contributions in Aid of Construction (CIAC)	$ -	$ -	$ -
6	Less: Accumulated Amortization	-	-	-
7	Net CIAC	-	-	-
8	Total Advances and Contributions	$ -	$ -	$ -
9	Member Advances	$ (11,982,081)	$ -	$ (11,982,081)
	ADD:			
10	Working Capital	$ 9,881,264	$ -	$ 9,881,264
11	Plant Held for Future Use	$ -	$ -	$ -
12	Deferred Debits	$ -	$ -	$ -
13	**Total Rate Base**	$ 189,637,810	$ -	$ 189,637,810

References:
Column [A], Company Schedule B-1, Page 1
Column [B]: Schedule CSB-3
Column [C]: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Schedule CSB-3

OPERATING INCOME - TEST YEAR AND STAFF RECOMMENDED

Line No.	DESCRIPTION	[A] STAFF DIRECT TEST YEAR	[B] ADJUSTMENTS	[C] STAFF SURREBUTTAL TEST YEAR	[D] STAFF PROPOSED CHANGES	[E] STAFF SURREBUTTAL RECOMMENDED
	REVENUES:					
1	Class A Members, Non-Base Cost of Power Revenue	$ 37,818,004	$ (368,421)	$ 37,449,583	$ 9,477,998	$ 46,927,581
2	Class A Members, Base Cost of Power Revenue	$ 48,992,382	$ -	$ 48,992,382		$ 48,992,382
3	Total Class A Member Electric Revenue	$ 86,810,386	$ (368,421)	$ 86,441,965	$ 9,477,998	$ 95,919,963
4	Non-Class A, Non-Firm, & Non-Member	50,996,438	-	50,996,438	-	50,996,438
5	Total Electric Revenue	$ 137,806,824	$ (368,421)	$ 137,438,403	$ 9,477,998	$ 146,916,401
6	Other Operating Revenue	$ 1,481,322	$ -	$ 1,481,322	$ -	$ 1,481,322
7	**Total Revenues**	$ 139,288,146	$ (368,421)	$ 138,919,725	$ 9,477,998	$ 148,397,723
	EXPENSES:					
8	Operations - Production, Fuel	$ 59,014,728	$ (5,658)	$ 59,009,070	$ -	$ 59,009,070
9	Operations - Production, Steam	$ 8,764,555	$ -	$ 8,764,555	$ -	$ 8,764,555
10	Operations - Production, Other	$ 1,743,316	$ -	$ 1,743,316	$ -	$ 1,743,316
11	Operations - Other Pwr Supply, Demand	$ 5,769,587	$ (250,000)	$ 5,519,587	$ -	$ 5,519,587
12	Operations - Other Pwr Supply - Energy	$ 12,170,888	$ 250,000	$ 12,420,888	$ -	$ 12,420,888
13	Operations - Transmission	$ 8,036,486	$ -	$ 8,036,486	$ -	$ 8,036,486
14	Operations - Administrative and General	$ 9,525,760	$ -	$ 9,525,760	$ -	$ 9,525,760
15	Maintenance - Production, Steam	$ 9,512,257	$ 193,569	$ 9,705,826	$ -	$ 9,705,826
16	Maintenance - Production, Other	$ 2,809,881	$ -	$ 2,809,881	$ -	$ 2,809,881
17	Maintenance - Transmission	$ 8,828	$ -	$ 8,828	$ -	$ 8,828
18	Maintenance - General Plant	$ 63,958	$ -	$ 63,958	$ -	$ 63,958
19	Depreciation and Amortization	$ 7,539,289	$ -	$ 7,539,289	$ -	$ 7,539,289
20	ACC Gross Revenue Taxes	$ -	$ -	$ -	$ -	$ -
21	Taxes	$ 3,346,839	$ -	$ 3,346,839	$ -	$ 3,346,839
22	**Total Operating Expenses**	$ 128,306,372	$ 187,910	$ 128,494,282	$ -	$ 128,494,282
23	**Operating Margin Before Interest on L.T.- Debt**	$ 10,981,774	$ (556,331)	$ 10,425,443	$ -	$ 19,903,441
24	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***					
25	Interest on Long-term Debt	$ 13,313,164	$ -	$ 13,313,164	$ -	$ 13,313,164
26	Other Interest & Other Dedcutions	$ 342,390	$ -	$ 342,390	$ -	$ 342,390
27	**Total Interest & Other Deductions**	$ 13,655,554	$ -	$ 13,655,554	$ -	$ 13,655,554
28	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	$ (2,673,780)	$ (556,331)	$ (3,230,111)	$ -	$ 6,247,887
29	***NON-OPERATING MARGINS***					
30	Interest Income	$ 582,014	$ -	$ 582,014	$ -	$ 582,014
31	Other Non-operating Income	$ 1,380,437	$ -	$ 1,380,437	$ -	$ 1,380,437
32	**Total Non-Operating Margins**	$ 1,962,451	$ -	$ 1,962,451	$ -	$ 1,962,451
33	***EXTRAORDINARY ITEMS***	$ -	$ -	$ -	$ -	$ -
34	***NET MARGINS (LOSS)***	$ (711,329)	$ (556,331)	$ (1,267,660)	$ -	$ 8,210,338

35 References:
36 Column (A): Cooperative Schedule C-1, Pages 1 and 2
37 Column (B): Schedule CSB-12
38 Column (C): Column (A) + Column (B)
39 Column (D): Schedules CSB-1
40 Column (E): Column (C) + Column (D)

TEST YEAR OPERATING INCOME - STAFF DIRECT AND SURREBUTTAL

LINE NO.	DESCRIPTION	[A] STAFF DIRECT	[B] ADJ #2 Revenue and Expense Annualizations Ref: Sch CSB-14	[C] ADJ #4 Tracker Mechanism (Base Power Cost) Ref: Sch CSB-16	[D] ADJ #5 Overhaul Accrual Expense Ref: Sch CSB-17	[E] STAFF SURREBUTTAL
	REVENUES:					
1	Class A Members, Non-Base Cost of Power Revenue	$ 37,818,004	$ (368,421)	$ -	$ -	$ 37,449,583
2	Class A Members, Base Cost of Power Revenue	$ 48,992,382	$ -	$ -	$ -	$ 48,992,382
3	Total Class A Member Electric Revenue	$ 86,810,386	$ (368,421)	$ -	$ -	$ 86,441,965
4	Non-Class A, Non-Firm, & Non-Member	50,996,438	-	-	-	50,996,438
5	Total Electric Revenue	$ 137,806,824	$ (368,421)	$ -	$ -	137,438,403
6	Other Operating Revenue	$ 1,481,322	-	-	-	1,481,322
7	**Total Revenues**	$ 139,288,146	$ (368,421)	$ -	$ -	$ 138,919,725
8	***OPERATING EXPENSES:***					
9	Operations - Production, Fuel	$ 59,014,728	$ (5,658)	$ -	$ -	$ 59,009,070
10	Operations - Production, Steam	8,764,555 [1]	-		-	8,764,555
11	Operations - Production, Other	1,743,316 [2]		-	-	1,743,316
12	Operations - Other Pwr Supply, Demand	5,769,587	-	(250,000)	-	5,519,587
13	Operations - Other Pwr Supply - Energy	12,170,888 [3]	-	250,000	-	12,420,888
14	Operations - Transmission	8,036,486	-		-	8,036,486
15	Operations - Administrative and General	9,525,760	-	-	-	9,525,760
16	Maintenance - Production, Steam	9,512,257 [4]	-	-	193,569	9,705,826
17	Maintenance - Production, Other	2,809,881	-	-	-	2,809,881
18	Maintenance - Transmission	8,828	-	-	-	8,828
19	Maintenance - General Plant	63,958	-	-	-	63,958
20	Depreciation and Amortization	7,539,289	-	-	-	7,539,289
21	ACC Gross Revenue Taxes	-	-	-	-	-
22	Taxes	3,346,839	-	-	-	3,346,839
23	**Total Operating Expenses**	$ 128,306,372	$ (5,658)	$ -	$ 193,569	$ 128,494,282
24	**Operating Margin Before Interest on L.T.- Debt**	**$ 10,981,774**	$ (362,762)	$ -	$ (193,569)	**$ 10,425,443**
25	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***					
26	Interest on Long-term Debt	$ 13,313,164	$ -	$ -	$ -	$ 13,313,164
27	Other Interest & Other Dedcutions	342,390	-	-	-	342,390
28	**Total Interest & Other Deductions**	$ 13,655,554	$ -	$ -	$ -	$ 13,655,554
29	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	$ (2,673,780)	$ (362,762)	$ -	$ (193,569)	$ (3,230,111)
30	***NON-OPERATING MARGINS***					
31	Interest Income	$ 582,014	$ -	$ -	$ -	$ 582,014
32	Other Non-operating Income	1,380,437	-	-	-	1,380,437
33	**Total Non-Operating Margins**	$ 1,962,451	$ -	$ -	$ -	$ 1,962,451
34	***EXTRAORDINARY ITEMS***	$ -	-	-	-	-
35	***NET MARGINS (LOSS)***	$ (711,329)	$ (362,762)	$ -	$ (193,569)	$ (1,267,660)

Footnote Explanations

[1] Includes account nos. 500, 502 to 509
[2] Includes account nos. 546, 548 to 550
[3] Includes account nos. 555 to 557
[4] Includes account nos. 510 to 515

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Surrebuttal Schedule CSB-5

OPERATING INCOME ADJUSTMENT NO. 2 - REVENUE AND EXPENSE ANNUALIZATIONS

		[A]	[B]	[C]
LINE NO.	**DESCRIPTION**	**STAFF DIRECT**	**STAFF ADJUSTMENTS**	**STAFF SURREBUTTAL**
1	Class A Member Demand Revenues	$ 36,990,731	$ (6,922,455)	$ 30,068,276
2	Class A Member Energy Revenues	$ 40,285,075	$ (14,260,705)	$ 26,024,370
3	Class A Member ACC Assessment Rev	$ -	$ -	$ -
4	Class A Member Fixed Charge Revenues	$ -	$ -	$ -
5	Total Class A Member Base Rate Revenues	$ 77,275,806	$ (21,183,160)	$ 56,092,646
6	Factor to Annualize Revenues to End of Test Year	1.65%		1.61%
7	**Revenue Annualization Adjustment**	$ 1,271,908	**$ (368,421)**	$ 903,487
8	Variable Expenses Not Recovered Through Fuel Adj	$ 16,062,410		$ 16,062,410
9	Factor to Annualize Revenues to End of Test Year	1.65%		1.61%
10	**Adjustment to Expenses**	$ 264,376	**$ (5,658)**	$ 258,718

11		**Calculation of Annualization Factor**						
12		Number of Customers						
13		Anza	Duncan	Graham	Mohave	Sulphur	Trico	Total
14	2002	3,702	2,446	7,481	-	43,113	27,631	84,373
15	2003	3,824	2,484	7,623	-	44,431	28,729	87,091
16	Increase	122	38	142	-	1,318	1,098	2,718
17	% Increase	3.30%	1.55%	1.90%	0.00%	3.06%	3.97%	3.22%

18 2003 Growth Rate 3.22%

19 Annualization Factor - 2003 Growth Rate divided by 2 1.6107%

20	**Calculation of Variable Expenses**			
21	**Not Recovered Through Fuel Adjustor**			
22	**Account**			
23	**No.**	**Description**	**Amount**	
24	500	Operation Supervision and Engineering	$ 1,999,908	
25	501&547	Fuel - Steam Power & Other	$ 59,803,425	
26	502	Steam Expenses	$ 2,710,803	
27	505	Electric Expenses	$ 1,437,524	
28	510	Maintenance Supervision & Engineering	$ 840,774	
29	512	Maintenance of Boiler Plant	$ 6,433,681	
30	513	Maintenance of Electric Plant	$ 264,759	
31	514	Maintenance of Miscellaneous Steam Plant	$ 2,374,961	
32	555	Purchased Power - Demand	$ 5,769,587	
33	555	Purchased Power - Energy	$ 10,085,538	
34		Total Variable Expenses	$ 91,720,960	
35	501&547	Fuel - Steam Power & Other	$ (59,803,425)	Recovered through Fuel Adj
36	555	Purchased Power - Demand	$ (5,769,587)	Recovered through Fuel Adj
37	555	Purchased Power - Energy	$ (10,085,538)	Recovered through Fuel Adj
38			$ 16,062,410	
39		2003 Growth Rate	1.61%	
40		Adjustment to Expenses	$ 258,718	

41 References:
42 Column A: Direct Testimony, CSB
43 Column B: Surrebuttal Testimony, CSB
44 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Surrebuttal Schedule CSB-6

OPERATING INCOME ADJUSTMENT NO. 4 - TRACKER MECHANISM (BASE POWER COST)

		[A]	[B]	[C]
LINE NO.	DESCRIPTION	STAFF DIRECT	ADJUSTMENTS	STAFF SURREBUTTAL
1	**Base Cost of Power Revenue**			
2	Test Year Sales (In kWhs)	2,025,326,533	-	2,025,326,533
3	Base Cost of Power (Col A, per Dec 58405)	$ 0.020380	$ -	$ 0.020380
4	**Adjustment to match Coop proposed power expense to revenue**	$ 41,276,155	$ -	$ 41,276,155
5	Test Year Sales (In kWhs)	2,025,326,533		2,025,326,533
6	Base Cost of Power (Col C, Line 53/Line 5)	$ 0.016570	$ -	$ 0.016570
7	**Adjustment to reflect Staff's adjustments to power costs**	$ 33,560,400	$ -	$ 33,560,400
8	**Total**	$ 33,560,400	$ -	$ 33,560,400
9	**Base Cost of Power Expense**			
10	Coal Fired Steam Plant Costs:			
11	Fuel, Coal ($1,534,274 Coop Adj No. 5 - $1,030,873 legal exp)	$ 42,532,932	$ -	$ 42,532,932
12	Fuel, Gas	2,309,354	-	2,309,354
13	Fuel, Oil	-	-	-
14	**Less:** Fixed Fuel Costs	(295,865)	-	(295,865)
15	Subtotal	$ 44,546,421	$ -	$ 44,546,421
16	Internal Combustion Plant Costs:			
17	Fuel, Gas	$ 15,454,731	$ -	$ 15,454,731
18	Fuel, Oil	9,809	-	9,809
19	Less: Fixed Fuel Costs	-	-	-
20	Subtotal	$ 15,464,540	$ -	$ 15,464,540
21	**Total Fuel Costs**	**$ 60,010,961**	**$ -**	**$ 60,010,961**
22	Purchased Power Energy Costs			
23	Firm Purchases			
24	CRSP	$ 309,547	$ -	$ 309,547
25	Pacificorp	-	-	-
26	Parker Davis	217,629	-	217,629
27	Public Service Company of New Mexico	1,713,061	250,000	1,963,061
28	Panda Gila River	1,134,573	-	1,134,573
29	Spinning Reserves	-	-	-
30	Subtotal Firm Purchases	$ 3,374,810	$ 250,000	$ 3,624,810
31	Nonfirm Purchases, Demand	$ 5,769,587	(250,000)	$ 5,519,587
32	Nonfirm Purchases, Energy	6,460,728	-	6,460,728
33	**Total Purchased Energy Costs**	**$ 15,605,125**	**$ -**	**$ 15,605,125**
34	**Firm Wheeling Expenses**	$ 7,939,635	-	$ 7,939,635
35	**Non-firm Wheeling Expenses**	77,291	-	77,291
36	**Total Firm and Non-Firm Wheeling Expenses**	**$ 8,016,926**	**$ -**	**$ 8,016,926**
37	**TOTAL FUEL COSTS & PURCHASED ENERGY**	**$ 83,633,012**	**$ -**	**$ 83,633,012**
38	**Less:**			
39	Non-tariff Sales Fuel Recovery			
40	TRICO PD Sierrita	$ 862,555	$ -	$ 862,555
41	City of Mesa	-	-	-
42	City of Mesa (PSA)	2,566,472	-	2,566,472
43	ED-2 Power Supply	1,356,004	-	1,356,004
44	SRP	12,778,277	-	12,778,277
45	Safford	232,895	-	232,895
46	Mohave Schedule B Sales	142,921	-	142,921
47	Subtotal	$ 17,939,124	$ -	$ 17,939,124
48	Other Sales Fuel Recovery:			
49	Non-Firm Sales	$ 8,394,266	$ -	$ 8,394,266
50	Total Non-Tariff Sales Fuel Recovery, Energy	$ 26,333,390	$ -	$ 26,333,390
51	Total Non-Tariff Sales Fuel Recovery, Demand	$ 23,739,222	$ -	$ 23,739,222
52	**Total Non-Tariff Sales Fuel Recovery, Energy and Demand**	**$ 50,072,612**	**$ -**	**$ 50,072,612**
53	**Member Fuel Costs-Base Cost of Pwr Exp (Line 37 - Line 52)**	**$ 33,560,400**	**$ -**	**$ 33,560,400**

54 References:
55 Column A: Decision No. 58405, page 29, line 25; Cooperative Application Schedule H-2A
56 Column B: Testimony, CSB
57 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Surrebuttal Schedule CSB-7

OPERATING INCOME ADJUSTMENT NO. 5 - OVERHAUL ACCRUAL EXPENSE

LINE NO.	DESCRIPTION	[A] STAFF DIRECT	[B] ADJUSTMENTS	[C] STAFF SURREBUTTAL
1	Overhaul Accrual Expense	$4,129,720	**$ 193,569**	$ 4,323,289

		ST1	ST2	ST3	GT1	GT2*	GT3	GT4**	Total
2									
3	1996	$ -	$ -	$ 5,180,041	$ -	$ -	$ -	$ -	$ 5,180,041
4	1997	$ -	$ 2,671,333	$ 489,239	$ -	$ -	$ -	$ -	$ 3,160,572
5	1998	$ -	$ -	$ 1,775,453	$ -	$ -	$ -	$ -	$ 1,775,453
6	1999	$ -	$ 3,828,921	$ -	$ -	$ -	$ 2,347,954	$ -	$ 6,176,875
7	2000	$ 94,116	$ 381,564	$ 1,181,848	$ -	$ -	$ -	$ -	$ 1,657,528
8	2001	$ 3,100,357	$ 2,740,233	$ -	$ 3,172,225	$ -	$ -	$ -	$ 9,012,815
9	2002	$ -	$ -	$ 2,868,220	$ -	$ -	$ -	$ -	$ 2,868,220
10	2003	$ -	$ 3,148,905	$ -	$ -	$ -	$ -	$ 1,605,900	$ 4,754,805
11		$ 3,194,473	$ 12,770,956	$ 11,494,801	$ 3,172,225	$ -	$ 2,347,954	$ 1,605,900	$ 34,586,309
12								Divided by	8
13									$ 4,323,289

14 * Per response to CSB 1-38, there has been no actual overhaul expense
15 for generating GT2 for the period 1990 to 2004.

16 ** Per response to CSB 1-37, unit GT4 was placed in service in 2002.
The Cooperative estimates that the cost of the overhaul, anticipated to occur
in eight years, will be $1,605,900.

17 References:

18 Column A: Cooperative Data Request Response CSB 1-37 and 1-38
19 Column B: Testimony, CSB
20 Column C: Column [A] + Column [B]

RAMIREZ

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01773A-04-0528

SURREBUTTAL

TESTIMONY

OF

ALEJANDRO RAMIREZ

PUBLIC UTILITIES ANALYST III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 4, 2005

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SCHEDULES

EXECUTIVE SUMMARY
ARIZONA ELECTRIC POWER COOPERATIVE, INC.
DOCKET NO. E-01773A-04-0528

The surrebuttal testimony of Staff witness Alejandro Ramirez addresses the following issues:

Operating Income, TIER and DSC Ratios – Staff recommends operating revenues no less than the $148,397,723 proposed by Arizona Electric Power Cooperative, Inc. ("AEPCO" or "Applicant"). AEPCO's proposed revenues would provide a times interest earned ratio ("TIER") of 1.50 and a debt service coverage ("DSC") ratio of 0.99. The Applicant's proposed revenue fails to provide sufficient internally generated operating cash flow to meet its debt service obligations.

Capital Structure – Staff recommends that the Applicant improve its equity position to 30 percent of the capital structure in a reasonable timeframe.

Staff also recommends that the Commission adopt a patronage distribution restriction for SWTCO that is no less restrictive than the Applicant's existing debt covenants.

Staff further recommends the Commission require AEPCO to file another rate case within at most three (3) to five (5) years after the effective date of a decision in this proceeding.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Alejandro Ramirez. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Are you the same Alejandro Ramirez who previously filed direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of this surrebuttal testimony is to respond to the rebuttal testimonies of Mr. Minson and Mr. Pierson. I also present Staff's position in regard to the Applicant's proposed operating income, times interest earned ratio ("TIER"), debt service coverage ration ("DSC"), and AEPCO's equity position.

I. UPDATED OPERATING REVENUES RECOMMENDATION

Q. What is Staff's updated recommended operating income for the Applicant?

A. Staff recommends an operating income of no less than $19,903,441, which is the same operating income that would result from the revenues proposed in AEPCO's rebuttal testimony.

Q. What TIER and DSC ratios would result from Staff's minimum recommended operating income of $19,903,441?

A. An operating income of $19,903,441 would produce a 1.50 TIER and a 0.99 DSC.

Q. Do you have any comments on AEPCO's updated recommended operating income of $19,903,441?

A. Yes. Although AEPCO's updated proposed operating income is higher than the proposed operating income in AEPCO's original filing, Staff is still concerned with the Applicant's capacity to service its current outstanding debt, finance future capital projects, and its capacity to improve its equity position.

Q. What TIER and DSC ratios is the Applicant claiming would result from AEPCO's updated proposed revenues?

A. AEPCO claims that its updated proposed revenues of $148,397,723 would produce a 1.62 TIER and a 1.05 DSC.

Q. Why are these ratios different from Staff's TIER and DSC?

A. Staff calculates TIER and DSC ratios differently from AEPCO [which calculates the TIER and DSC in the same manner as the Rural Utility Service ("RUS")]. AEPCO takes into account non-operating revenues when calculating the TIER and DSC while Staff does not. Staff does not take into account non-operating revenues when calculating TIER and DSC ratios because those revenues are not the direct result of AEPCO's regulated activities. Staff cannot foretell whether these non-operating revenues will continue in the future. A decrease in non-operating revenues may negatively impact AEPCO's ability to service its debt; therefore, if AEPCO's TIER and DSC calculations provide a less reliable basis for determining debt service capacity.

Q. Why is Staff concerned with AEPCO's capacity to service its current outstanding debt?

A. Staff is concerned with AEPCO's capacity to service its current outstanding debt because the Applicant's proposed operating income would result in a 1.50 TIER and a 0.99 DSC (Staff's calculated TIER and DSC). As stated in Staff's direct testimony, the DSC ratio represents the number of times internally generated cash will cover payments on both interest and principal. A DSC equal to 0.99 means that if there is no change from the assumptions built into recommended rates, the Applicant cannot meet all of its existing debt service obligations with cash generated from operations. Only with recognition of non-operating cash flow does the Applicant barely cover both its principal and interest payments. Any detrimental change (even slight) in the economic environment resulting in erosion of AEPCO's operating or non-operating revenue or increasing expenses would exacerbate the Applicant's capacity to service its current debt obligations.

Q. Why is Staff concerned with AEPCO's capacity to finance future capital projects?

A. AEPCO's capacity to finance future capital projects may be negatively affected given that Staff has calculated a 0.99 DSC based on AEPCO's proposed revenues. Additional financing for capital projects would result in an even lower DSC for the Applicant. The Applicant has requested the Commission to authorize AEPCO to incur additional debt financing for $8.4 million (Docket No. E-01773A-04-0793). By Staff's calculations, AEPCO will not be able to service this additional debt with its proposed revenues alone. Therefore, Staff will recommend denial of this financing unless AEPCO modifies its revenue request. In addition, any other future debt financing will be seriously compromised given the Applicant's proposed revenues.

Q. What is AEPCO's current financial situation?

A. AEPCO's witness and Chief financial Officer, Dirk Minson, stated in his rebuttal testimony that the Applicant is out of compliance with RUS. This non-compliance negatively impacts AEPCO's capacity to incur any new debt. An even more immediate and important effect is the potential limitation for AEPCO to draw any funds from currently authorized loans. This is one example of the Applicant's need to improve its financial position. Operating revenues that provide a DSC equal to 0.99 do not help mitigate AEPCO's immediate financial problems, and fail to recognize a solid solution for the long-run.

Q. What is Staff's current position on the Applicant's updated proposed operating income?

A. Staff recommends that the Commission approve operating revenues for AEPCO that would result in an operating income of no less of $19,903,441 (which is the same operating income that the Applicant is requesting). However, Staff expects the Applicant to address its precarious proposed revenue requirement soon. AEPCO must address this situation in the very near future because the proposed revenue provides for virtually no current borrowing capacity, severely limits future borrowing capacity and does little to improve its highly leveraged capital structure.

II. COMMENTS ON MR. MINSON'S REBUTTAL TESTIMONY

Q. Do you have any general comments on Mr. Minson's rebuttal testimony?

A. Yes. As Mr. Minson stated in his direct testimony, AEPCO and Staff recognize the need for a rate increase to improve the Applicant's financial position. Staff also recognizes that AEPCO had improved its equity position to 7 percent of the total assets by 2002 (compared with its negative equity position of 14.9 percent in 1991). In addition, Staff recognizes AEPCO's effort to decrease its member rates. However, it is Staff's position that AEPCO's rates should be sufficient to move toward a sound financial position while also taking into account the ratepayer impact.

Q. Do you have any comments in regard to Mr. Minson's recommended DSC of 1.05 as the basis to calculate the proposed revenue levels?

A. Yes. Previously in this testimony, it was explained that the Applicant's and Staff's TIER and DSC are calculated in a different manner. The Applicant's proposed DSC of 1.05 takes into account non-operating revenues where Staff does not. Therefore, the Applicant's updated proposed revenues will in fact produce a lower Staff DSC. Although RUS may provide additional financing to AEPCO if the Applicant's updated proposed revenues are approved by the Commission, AEPCO's capacity to service its debt payments may be reduced, leaving no cushion for unexpected events. The Applicant may find that its updated proposed revenues are insufficient to support any additional debt financing needed for capital improvements.

Q. Does Mr. Minson contest Staff's recommendation to improve AEPCO's equity position?

A. While Mr. Minson agrees with Staff that the Applicant should continue to build its equity position, he disagrees with Staff's recommendation that AEPCO should increase its equity position to 30 percent of the capital structure.

Q. Does Mr. Minson recommend a specific equity position goal for the Applicant?

A. No. Mr. Minson's opinion is that an equity position of 30 percent is simply too high. Mr. Minson refers to the Schedule presented by Staff in Direct testimony that shows that the average equity position for the sample generation and transmission ("G&T") companies is 19 percent. He also refers to the R.W. Beck 2002 survey which indicated that the equity ratio goal of the cooperatives surveyed was 17.5 percent.

Q. What is Staff's position in regard to AEPCO's equity position?

A. Staff's position is that AEPCO should improve its equity position to at least 30 percent. Staff's position reflects a prior Commission decision (Decision No. 64227, dated November 29, 2001), and AEPCO's need to achieve greater financial flexibility. Also, and article published by Fitch Ratings, a well known rating agency, stated that an equity-to-capitalization ratio between 25 to 30 percent is adequate for a generation and transmission cooperative (See Attachment 1).

Q. Do you have any comments in regard to Mr. Minson's statement that setting a 30 percent equity goal will result in AEPCO's inflexibility to react to economic and financial changes?

A. Yes, Staff understands Mr. Minson's concerns that there might be factors that may not allow AEPCO to achieve the 30 percent equity goal. Staff is aware that economic and financial conditions do change over time. Staff also understands the there is the need to balance reasonable rates and the financial health of the Applicant. However, it is Staff's position that the Applicant should commit to improve its equity position to at least 30 percent. Staff recommends consistently balancing the effort to achieve a healthy financial position with other considerations.

Q. Does Mr. Minson take any position in regard to Staff's recommendation of restricting future patronage distributions until the Applicant has achieved a 30 percent capital structure?

A. Yes. Mr. Minson states that AEPCO does not have any plans for the foreseeable future to make any patronage distributions. However, Mr. Minson proposes that if Commission places any restriction on patronage distributions, it should be the same restriction presented by the Applicant's debt covenants.

Q. Does Staff have any comments on the restriction of patronage distributions?

A. Yes. Instead of distributing patronage dividends, the Applicant could use those funds to fund, in full or at least partially, future capital projects, thereby increasing its equity position. As mentioned earlier in this testimony, Staff is concerned with AEPCO's current and future borrowing capacity. Staff supports the Commission adopting a patronage distribution restriction for AEPCO that is in accordance with, or even more restrictive than, the Applicant's existing debt covenants.

Q. Do you have any other recommendations for AEPCO?

A. Yes. Given that the Applicant agrees with Staff that AEPCO needs to increase its equity position, but has not shown any specific plan or target to accomplish it, Staff recommends that the Commission order AEPCO to file an equity improvement plan by December 31, 2005. Staff also recommends that the Commission order AEPCO to file a status report with Director of the Utilities Division by March 30 each year showing its equity position and changes from the prior year. Staff strongly recommends that AEPCO consider filing rate cases more frequently. Staff further recommends that the Commission order AEPCO to file another rate case within at most three (3) to five (5) years after the effective date of an order in this proceeding.

CONCLUSION

Q. What is Staff's recommended operating income for AEPCO?

A. Staff recommends an operating income for AEPCO of no less than $19,903,441. A 1.50 TIER and a 0.99 DSC would result from Staff's minimum operating income. Staff is concerned with the Applicant's current and future capacity to service its debt. Staff is also concerned with the Applicant's borrowing capacity.

Staff further recommends that the Commission require AEPCO to improve its equity position to at least 30 percent. Staff also recommends that the Commission adopt a patronage distribution restriction for AEPCO that is no less restrictive than the Applicant's existing debt covenants.

Staff further recommends that the Commission require AEPCO to docket an equity improvement plan by December 31, 2005.

Staff further recommends the Commission require AEPCO to docket a calendar year status report by March 30 each year showing its equity position and changes from the prior year.

Staff further recommends the Commission require AEPCO to file another rate case within at most three (3) to five (5) years after the effective date of a decision in this proceeding.

Q. Does this conclude your surrebuttal testimony?

A. Yes it does.

AEPCOS' TIER and DSC With Staff's Updated Recommended Rates[1]

1	Operating Income	$ 19,903,441	**TIER**	
2	Depreciation & Amort.	$ 7,539,289	[1+3] ÷ [5]	1.50
3	Income Tax Expense	$ -	**DSC**	
4			[1+2+3] ÷ [5+6]	0.99
5	Interest Expense	$ 13,313,164		
6	Repayment of Principal	$ 14,360,494		

[1] The amounts reflect Staff's pro forma adjustments and Staff's recommended revenue

Fitch Initiates Coverage of Golden Spread Electric Cooperative with 'A-' Rating

02 Mar 2005 4:14 PM (EST)

Fitch Ratings-New York-March 2, 2005: Fitch Ratings assigns an initial senior secured rating of 'A-' to Golden Spread Electric Cooperative, Inc.'s (Golden Spread) $55 million 2005 private placement. The Rating Outlook is Stable. Proceeds will be used to repay Golden Spread for the acquisition and construction costs incurred to date and to complete the construction of a 145-mw gas-fired combustion turbine peaking unit. The 2005 financing will be priced in March 2005 with La Salle Capital as sole placement agent.

The foundation of Golden Spread's long-term rating derives from a pledge of revenues from the company's full-requirement contracts with its 16 members through the life of the bonds. In addition, bondholders will be secured by a lien on the 145-mw peaking units as well as surplus cash from Golden Spread's sale of energy from current and future affiliated power projects. Other positive credit factors include favorable intermediate-term partial-requirement power supply arrangements with Southwestern Public Service Company (SPS), a wholly owned subsidiary of Xcel Energy, experienced management and consultants, and a solid financial profile.

Credit concerns include Golden Spread's need to develop power supply to replace its SPS partial-requirement agreement that expires in 2012, its higher than average concentration of commercial and irrigation customers among its members' retail loads (representing more than 70% of member revenues), the need to maintain adequate liquidity and financial margins in the future, and lean management team.

In 1984, 11 distribution utilities formed Golden Spread to consolidate their interests and provide power supply alternatives to SPS. In this role, Golden Spread negotiated a partial-requirement power supply arrangement and dispatch arrangement (both of which expire in 2012). These arrangements provides Golden Spread the flexibility to utilize at its discretion over 300 mw of SPS resources (with a fuel mix of 2/3 coal and 1/3 gas) and the full capacity of the Mustang Station, a 483-mw combined-cycle plant that has been on-line since 2000. As part of the dispatch arrangement with SPS, Golden Spread is able to sell its excess energy from Mustang at favorable rates that help reduce its wholesale cost of power. Fitch views these arrangements as positive and stable factors in Golden Spread's credit profile.

With the forthcoming expiration of the SPS partial-requirement agreement and the need to increase its power supply, Golden Spread is currently developing and implementing a generation expansion program. In the next seven years, Golden Spread's capital expenditures will total over $800 million (funded with approximately 80% debt and 20% cash) to fund various coal and gas-fired generation projects.

The 'A-' rating is based on Golden Spread's solid historical operations, and assumes the cooperative is successful in its implementation of a diversified and adequate power supply portfolio while maintaining sound financial results. Fitch recognizes the majority of the planned projects are in the early stages of development and that Golden Spread could modify its plan as the wholesale market and power supply alternatives change. Fitch is comforted by Golden Spread's track record in developing the Mustang Station and the experience of its management and long-time consultants. Nevertheless, unexpected delays or substantial project cost increases above projections could become a negative credit factor should they compromise Golden Spread's financial strength or if they significantly affect the members' retail customers' cost of power and financial viability.

Although the new projects will substantially increase Golden Spread's leverage and annual debt service requirements, current and projected ratios are well above average for the rating category and include 2003 debt service coverage of 2.3 times (x) and equity-to-capitalization of 31%. Unaudited results for fiscal-year 2004 are in-line with historical levels. For the future, management expects to maintain a minimum debt service coverage ratio of 1.5x and equity-to-capitalization ratios between 25%-30%, which is good for a generation and transmission cooperative.

Golden Spread's future generation units could be funded as separate projects whereby a portion of a project's cash and equity would be segregated from Golden Spread and the 2005 bondholders. Fitch does not consider this risk as meaningful, since each of the projects would likely be serving a majority, if not all members, and operating margins and cash reserves at any individual project should not be significant.

Golden Spread has over $20 million in cash reserves and also maintains $110 million in available liquidity facilities. In aggregate, this liquidity provides over six months of operating expenses. In addition to these funds, Golden Spread has approximately $40 million in cash that is pledged to a future power project. Further bolstering its liquidity profile, Fitch views positively Golden Spread's competitive wholesale rates and a structure that automatically adjusts for changes in fuel and purchased power costs on a monthly basis. Golden Spread plans to use a portion of its current and projected cash balances over the next few years to partially fund the costs of its various planned generation projects. With lower levels of cash projected during that period, Fitch will look for Golden Spread to maintain sufficient levels of liquidity with available lines of credit and conservative revenue requirement projections.

Golden Spread is a not-for-profit generation and transmission cooperative providing electric service to 16 distribution cooperatives. Fifteen members are located in Texas' Panhandle, South Plains and Edward Plateau regions and one member is located in the Oklahoma Panhandle region. The service area of Golden Spread's Texas members represent approximately 24% of the land mass of Texas. In 2003, Golden Spread's membership increased to 16 members from the original 11. The 16 distribution members serve nearly 200,000 customers.

In 2004, Golden Spread's total revenues were almost $411 million, with 66% representing revenues under long-term member contracts and 34% from sales to SPS.

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KEENE

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF) ARIZONA ELECTRIC POWER COOPERATIVE,) INC. FOR A RATE INCREASE)	DOCKET NO. E-01773A-04-0528

SURREBUTTAL

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 4, 2005

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APPENDICES

EXECUTIVE SUMMARY
ARIZONA ELECTRIC POWER COOPERATIVE/
DOCKET NO. E-01773A-04-0528

Ms. Keene's testimony recommends that a fuel and purchased power cost adjustor include the margins from non-Class A sales as an offset to costs. The base costs of fuel and purchased power be set at $0.01687 per kWh for full requirements customers and $0.01603 per kWh for the partial requirements customer.

Ms. Keene's testimony recommends that AEPCO engage in cost-effective DSM programs. AEPCO should be allowed to recover its program costs for pre-approved DSM projects through a DSM adjustment mechanism.

Ms. Keene's testimony recommends new rates for AEPCO in order for AEPCO to recover Staff's recommended revenue requirements. These rates would result in an overall increase for Class A members of 10.9 percent. Mohave Electric's increase would be 15.5 percent, while the increase for the other distribution cooperatives would range from 8.6 to 8.9 percent each.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony concerning a fuel and purchased power cost adjustor, a demand-side management ("DSM") adjustor, and rate design for Arizona Electric Power Cooperative ("AEPCO").

Q. As part of your employment responsibilities, were you assigned to review AEPCO's rebuttal testimony?

A. Yes. I conducted a review of the testimonies of Mr. Dirk Minson and Mr. Gary Pierson concerning the fuel and purchased power cost adjustor, DSM, and rate design.

FUEL AND PURCHASED POWER COST ADJUSTOR

Q. What did AEPCO's witness Mr. Minson include in his rebuttal testimony regarding Staff's recommendations about a fuel and purchased power adjustor?

A. Mr. Minson, on pages 10 and 11 of his rebuttal testimony, disagrees with Staff's recommendation to credit all revenue from non-Class A sales to the adjustor balance as an offset to costs.

Q. What are Mr. Minson's reasons for excluding the margins received from such sales in the adjustor?

A. Mr. Minson has stated three reasons for the exclusion: 1) the margins have already been credited to reduce members' cost of service in proposed rates, 2) crediting margins from economy sales would distort the true price signal concerning fuel and purchase power costs sent to members through the adjustor, and 3) margins from non-member economy sales are a way for AEPCO to build equity.

Q. Please respond to Mr. Minson's reasons for excluding the margins of non-Class A sales from the adjustor.

A. Even though the margins have been credited to reduce members' cost of service in the Class A member tariff base rates, the margins should also be included in the adjustor. The adjustor base cost of fuel and purchased power reflects what is in the adjusted test year, and recovered through the Class A member tariff rates, for both costs and revenues. The adjustor base is used for comparison to later fuel and purchased power costs and non-Class A sales revenues. It is the difference between the adjustor base and later fuel and purchased power costs and non-Class A sales revenues that would be recovered through the adjustor rate. Thus, the fact that revenues from non-Class A member sales are accounted for in the base rates does not mean that they should be ignored in the adjustor. Those revenues may be different in any given year than what is reflected in the base rates, and the adjustor should account for the difference.

Mr. Minson also claims that crediting margins from economy sales would distort the true price signal concerning fuel and purchased power costs sent to members through the adjustor. However, leaving out an important component from the adjustor would distort the price signal. Price signals should reflect the true cost the company incurs, and the company's fuel and purchased power costs are offset by non-Class A sales. Including all revenue from non-Class A sales for resale as an offset to costs allows the Class A members to benefit from the margins of those sales. Since Class A members pay for the costs of the resources, it only seems fair that they benefit from the non-Class A sales.

Margins from non-member economy sales could help AEPCO to build equity, but the adjustor is not the proper mechanism to address that issue. Equity is addressed in operating margins.

Q. What did AEPCO witness Mr. Pierson recommend in his rebuttal testimony regarding the adjustor?

A. On page 6 of his rebuttal testimony, Mr. Pierson recommends that there be two bases for fuel and purchased power costs - one for the all (full) requirements customers and one for the partial requirements customer.

Q. Why did Mr. Pierson recommend two bases for fuel and purchased power costs?

A. There are certain demand and wheeling costs that are not applicable to the partial requirements customer because Mohave elected to not participate in the Panda Gila River purchased power agreement.

Q. Does Staff agree with Mr. Pierson?

A. Yes.

Q. At what amounts should the base costs be set?

A. The base cost of fuel and purchased power should be set at $0.01687 per kWh for full requirements customers and $0.01603 per kWh for the partial requirements customer. Derivation of the base costs is shown in Appendix 1.

DEMAND-SIDE MANAGEMENT

Q. What did Mr. Minson include in his rebuttal testimony regarding DSM?

A. Mr. Minson, on pages 11 and 12 of his rebuttal testimony, states that AEPCO disagrees with Staff's proposal to establish a DSM program for AEPCO.

Q. Why does AEPCO take that position?

A. Mr. Minson states that AEPCO supports DSM, but that it is not appropriate for AEPCO, as a wholesale generator, to have a DSM program.

Q. What are AEPCO's reasons for DSM not being appropriate for AEPCO?

A. AEPCO's reasons are: 1) DSM programs are designed to affect end-use energy consumption, 2) there would likely be confusion by the end-use customer and a duplication of administrative costs, and 3) there is wide diversity among the distribution cooperatives served by AEPCO.

Q. Does Staff agree with AEPCO's contentions about DSM?

A. No.

Q. Please respond to AEPCO's reasons for not having a DSM program.

A. Although DSM does affect end-use consumption, the ultimate goal of DSM is often reducing peak demand in order to reduce the costs of generation and purchased power, which are incurred by AEPCO. Cost-effective DSM programs can meet the demand for electric energy services at a lower cost than purchasing or generating power. Reduced peak demand can delay the need for construction of new generation and transmission facilities. In addition, reducing energy needs reduces the operating costs of current generating facilities. Reduced energy production may also lead to reduced air emissions from power plants, reduced consumption of water by generating unit cooling towers, and reduced degradation of land at coal mining sites.

AEPCO would need to work with the distribution cooperatives to deliver programs to the end-users as they did in the past. It appeared to have been successful in the 1990s when AEPCO engaged in DSM. Some of the distribution cooperatives had there own programs, others only participated in AEPCO's programs. They benefited by AEPCO's expertise and coordination of efforts. Staff never heard of any end-use customer confusion at the time. There may even be a reduction in administrative costs rather than a duplication of costs if AEPCO develops the programs for the distribution cooperatives. AEPCO has begun developing renewable energy projects on behalf of the member cooperatives and therefore has experience in such coordination.

Staff agrees that there is diversity among the distribution cooperatives. However, there is a great deal that can be standardized while allowing flexibility regarding individual programs. For example, all of the distribution cooperatives might want to participate in a refrigerator program where AEPCO could negotiate with manufacturers or distributors. On the other hand, an air conditioner program might only be appropriate for the warmer weather cooperatives.

Q. What did Staff recommend in its direct testimony regarding AEPCO and DSM?

A. Staff recommended that AEPCO engage in cost-effective DSM programs and that AEPCO be allowed to recover its program costs for pre-approved DSM projects through a DSM adjustment mechanism. Staff did not recommend a specific DSM goal for AEPCO nor any specific programs.

Q. If a DSM cost recovery mechanism is not approved in this rate case, does that mean that AEPCO would not have to engage in DSM?

A. No. In another docket, Staff has filed a DSM policy that will be transformed into proposed rules. The proposed policy would require applicable utilities to file DSM plans for Commission approval.

Q. Would the proposed DSM rules apply to AEPCO?

A. Yes. The proposed rules are expected to apply to AEPCO. If those rules become effective, AEPCO would have to engage in DSM without any cost recovery mechanism unless the mechanism is approved in this rate case.

RATE DESIGN

Q. What do you recommend as AEPCO's rates for its Class A members?

A. Based on Staff's recommended revenue requirements contained in the Surrebuttal Testimony of Crystal Brown, the rates should be set as follows:

Full Requirements

Demand charge	$13.99 per kW of demand coincident with AEPCO monthly peak
Energy charge	$0.02073 per kWh used during billing period

Partial Requirements

O&M charge	$7.09 per kW of allocated capacity based on coincident AEPCO demand
Energy charge	$0.02073 per kWh used during billing period
Fixed Charge	$758,466 per month for Mohave

These rates would result in an overall increase for Class A members of 10.9 percent. Mohave Electric's increase would be 15.5 percent, while the increase for the other distribution cooperatives would range from 8.6 percent to 8.9 percent each. Mohave's percentage is higher than that of the full requirements members because the full requirements members have increasing billing units. As a partial requirements customer, Mohave's rates do not reflect an increase in billing units. However, the relative contribution of Mohave's revenue to the total Class A member revenue is about the same between existing AEPCO rates and proposed rates.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. 1. Staff recommends that a fuel and purchased power cost adjustor include the margins from non-Class A sales as an offset to costs.

2. Staff recommends that the base cost of fuel and purchased power be set at $0.01687 per kWh for full requirements customers and $0.01603 per kWh for the partial requirements customer.

3. Staff recommends that AEPCO engage in cost-effective DSM programs.

4. Staff recommends that AEPCO be allowed to recover its program costs for pre-approved DSM projects through a DSM adjustment mechanism.

5. Staff recommends new rates for AEPCO in order for AEPCO to recover Staff's recommended revenue requirements. These rates would result in an overall increase for Class A members of 10.9 percent. Mohave Electric's increase would be 15.5 percent, while the increase for the other distribution cooperatives would range from 8.6 percent to 8.9 percent each.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

Base Cost of Fuel and Purchased Power
for AEPCO Adjustor
Partial Requirements

RUS Account			
501	fuel costs for steam power generation		$46,830,878
	less MEC Schedule A adjustment		-550,220
	less City of Mesa adjustments		-407,498
	less legal fees		-1,030,873
	less fixed fuel costs (except gas reservation)		-295,865
			$44,546,422
547	fuel costs for other power generation		**$15,464,540**
555	purchased power costs (demand & energy)		$16,270,579
	less MEC Schedule A adjustment		-333,790
	less City of Mesa adjustments		-169,803
	plus Purchase Power adjustment		88,139
	less PNM adjustment		-250,000
	less Panda Gila demand*		-1,000,872
			$14,604,253
565	wheeling costs (firm & non-firm)		$8,036,486
	plus wheeling contract adjustment		-19,560
	less El Paso Wheeling*		-102,500
			$7,914,426
		Costs	***$82,529,641***
447	non-Class A sales for resale		$51,757,181
	plus MEC Schedule B reclassification		142,921
	less City of Mesa adjustments		-903,664
	less revenue for legal expenses		-923,826
		Revenues	***$50,072,612***
	Base cost (costs-revenues)		$32,457,029
	Class A kWh sales		2,025,326,533
	Partial Requirements Base Cost Rate	**$/kWh**	**$0.01603**
	Mohave kWh sales		716,978,668
	Mohave base cost		**$11,489,998**

* Mohave elected to not participate in the Panda Gila River purchased power agreement.

Base Cost of Fuel and Purchased Power
for AEPCO Adjustor
Full Requirements

RUS Account			
501	fuel costs for steam power generation		$46,830,878
	less MEC Schedule A adjustment		-550,220
	less City of Mesa adjustments		-407,498
	less legal fees		-1,030,873
	less fixed fuel costs (except gas reservation)		-295,865
			$44,546,422
547	fuel costs for other power generation		**$15,464,540**
555	purchased power costs (demand & energy)		$16,270,579
	less MEC Schedule A adjustment		-333,790
	less City of Mesa adjustments		-169,803
	plus Purchase Power adjustment		88,139
	less PNM adjustment		-250,000
			$15,605,125
565	wheeling costs (firm & non-firm)		$8,036,486
	plus wheeling contract adjustment		-19,560
			$8,016,926
		Costs	***$83,633,013***
447	non-Class A sales for resale		$51,757,181
	plus MEC Schedule B reclassification		142,921
	less City of Mesa adjustments		-903,664
	less revenue for legal expenses		-923,826
		Revenues	***$50,072,612***
	Base cost (costs-revenues)		$33,560,401
	Mohave base cost		-$11,489,998
	Full Requirements Base Cost		**$22,070,403**
	Class A kWh sales (less Mohave)		1,308,347,865
	Full Requirements Base Cost Rate	**$/kWh**	**$0.01687**

SURREBUTTAL

TESTIMONY

OF

CRYSTAL S. BROWN

ALEJANDRO RAMIREZ

ERIN CASPER

DOCKET NO E-04100A-04-0527

IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN

APRIL 4, 2005

BROWN

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-04100A-04-0527

SURREBUTTAL TESTIMONY

OF

CRYSTAL S. BROWN

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 4, 2005

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SCHEDULES

EXECUTIVE SUMMARY
SOUTHWEST TRANSMISSION COOPERATIVE, INC.
DOCKET NO. E-04100A-04-0527

Ms. Brown's surrebuttal testimony presents Staff's response to Southwest Transmission Cooperative, Inc.'s ("Southwest Transmission" or "Cooperative") rebuttal testimony regarding the regulatory asset charge and a $2.3 million contract termination effective January 1, 2006. Also, Staff responds to the Cooperative's comments on the redacted legal invoices, food and similar expenses, and jurisdictional separation.

INTRODUCTION

Q. Please state your name.

A. My name is Crystal S. Brown.

Q. Are you the same Crystal S. Brown who previously submitted pre-filed testimony in this docket?

A. Yes, I am.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond, on behalf of the Utilities Division ("Staff"), to the rebuttal testimony of Southwest Transmission Cooperative Inc.'s ("Southwest Transmission" or the "Cooperative") rebuttal testimony regarding the regulatory asset charge and a $2.3 million contract termination effective January 1, 2006. Also, Staff responds to the Cooperative's comments on the redacted legal invoices, food and similar expenses, and jurisdictional separation.

SUMMARY OF COOPERATIVE'S REBUTTAL TESTIMONY

Q. Please summarize Southwest Transmission's rebuttal testimony.

A. Southwest Transmission's rebuttal testimony suggests that Staff's reclassification of the regulatory asset charge revenue should be matched with a reclassification of the related regulatory asset charge amortization expense. Additionally, the Cooperative proposed a second set of rates to become effective January 1, 2006, to recover $2,294,640 of revenue it will lose on that date due to the termination by Morenci Water and Electric of a 60 MW firm point-to-point contract. The Cooperative also comments, by way of reference to the rebuttal testimony of Arizona Electric Power Cooperative, Inc. (Docket No. E-01773A-

040528),[1] on the redacted legal invoices, food and similar expenses, and jurisdictional separation.

REGULATORY ASSET CHARGE ("RAC")

Q. What is Southwest Transmission's rebuttal response to Staff's Operating Income Adjustment No. 1, "Regulatory Asset Charge" that reclassified RAC revenue from operating to non-operating revenue and reduced the amount from $2,707,122 to $2,559,926?

A. Southwest Transmission accepted Staff's adjustment, and suggested that a corresponding adjustment to reclassify the associated amortization of the RAC asset from operating to non-operating expense is appropriate.

Q. Does Staff agree with Southwest Transmission's position that the amortization of the RAC asset from operating to non-operating expense is appropriate?

A. Yes.

Q. What is Staff recommending?

A. Staff recommends removing the $2,707,122 RAC amortization expense recorded in the Test Year from operating expense and recognizing $2,559,926 of non-operating amortization expense as shown on Surrebuttal Schedules CSB-4 and CSB-5.

[1] Minson Rebuttal testimony, pages 5 through 7

MW&E 60MW FIRM POINT-TO-POINT CONTRACT TERMINATION

Q. What amount of revenue did the Cooperative collect under the MW&E 60MW Firm Point-to-Point contract during the Test Year?

A. Southwest Transmission collected $2,294,640 under the MW&E 60MW Firm Point-to-Point contract during the Test Year.

Q. When will the MW&E firm point-to-point contract terminate?

A. The contract will terminate January 1, 2006.

Q. How does Southwest Transmission propose to address the $2.3 million revenue loss?

A. The Cooperative requests that the Commission authorize a second set of rates to become effective January 1, 2006, to recover the $2,294,640 revenue loss due to termination of the MW&E 60 MW point-to-point contract from other customers.

Q. Does Staff support Southwest Transmission's proposal for authorization of a second set of rates to recover the anticipated loss of the MW&E revenue?

A. Yes.

Q. What is Staff recommending?

A. Staff recommends authorization of a second set of rates to become effective January 1, 2006, to recover the revenue that will be lost due to termination of the MW&E contract. Staff's proposed rates for the second phase are presented in the surrebuttal testimony of Staff witness Ms. Erin Casper.

REDACTED LEGAL INVOICES AND MINUTES OF THE BOARD OF DIRECTORS

Q. What is Southwest Transmission's rebuttal response to Staff's adjustment to disallow costs related to certain legal invoices and minutes of the board of directors?

A. Southwest Transmission accepted Staff's adjustment. Although Staff does agree with the Cooperative's other statements on this matter, there is no further need to comment on the matter beyond what Staff stated in its direct testimony.

FOOD AND OTHER EXPENSE

Q. What is Southwest Transmission's rebuttal response to Staff's adjustment to disallow costs related to food and other similar expenses?

A. Southwest Transmission accepted Staff's adjustment. However, the Cooperative claims that many of the expenses, such as food for the Member Meetings, training, and recruitment were necessary for safe, reliable, and adequate service.

Q. Are food, entertainment, and similar expenses needed in the provision of safe, reliable service?

A. No, they are non-essential costs for the provision of service.

Q. How are customers affected when non-essential costs are included in rates?

A. Customers are unnecessarily charged higher rates when non-essential costs are built into rates. If this occurs, a portion of each customer's bill would pay for the non-essential costs. These non-essential costs could be reduced or eliminated and the customers' transmission service would not be affected.

JURISDICTIONAL SEPARATION

Q. What is Southwest Transmission's rebuttal response to Staff's recommendation that it "separate nonjurisdictional properties, revenues and expenses" in compliance with the Arizona Administrative Code?

A. Southwest Transmission did not accept Staff's recommendation because (1) the Commission had never required the Cooperative to jurisdictionally separate the rate base and expenses for its California customer (i.e., Anza) and (2) the benefit derived from such compliance would not justify the cost.

Q. Is the Cooperative's argument that it has never been required to perform a cost of service study for Anza since 1979 justification for not jurisdictionally separating rate base and expenses?

A. No. Previous non-filing of jurisdictionally separated data is not justification for continued non-filing of jurisdictionally separated data. The Cooperative's response indicates that the Cooperative does not know nor has ever known (based upon a study) what the rate base and expense elements are for Anza.

Q. Has the Cooperative supported its assertion that the benefits of the jurisdictional separations requirements would exceed the costs?

A. No. The Cooperative does not know the benefits. The benefits cannot be determined until the jurisdictional separation is performed.

Q. Can Staff provide an example of the potential inequity that is presented by absence of jurisdictional separations.

A. Hypothetically, the cost to serve a customer that represents 2 percent of revenues could be 10 percent of costs. The result in such a case is a substantive subsidization for this customer. Staff cannot know if this situation is occurring unless the Cooperative provides jurisdictionally separated data.

Q. Does Staff believe that it would be cost prohibitive to jurisdictionally separate the data?

A. No, because smaller cooperatives have provided jurisdictionally separated data. In addition, other smaller cooperatives have also provided cost of service studies that allocate rate base, revenue, and expenses by customer class. Further, once the framework/methodology has been established, the process to update the studies should be relatively straightforward.

Q. What is the benefit of requiring jurisdictionally separated data?

A. The information would assist in the pricing out of contracts and development of cost-based rates.

Q. What is Staff recommending?

A. Staff continues to recommend that the Cooperative jurisdictionally separate the data in all subsequent rate filings.

SUMMARY OF STAFF'S SURREBUTTAL REVENUE POSITION

Q. Please summarize Staff's recommended revenue.

A. Staff recommends total annual operating revenue of no less than that proposed by Southwest Transmission, which is $28,814,864, an increase of 3,666,668, or 14.58 percent, over Staff adjusted Test Year revenues of $25,148,196. In addition, Staff and the Cooperative recognize $2,559,926 of non-operating RAC cash flow. The recommended revenue (including RAC) would produce an operating margin of $6,146,732 for an 8.05

percent rate of return on the original cost and fair value rate base of $76,235,655 to provide a 1.16 times interest earned ratio ("TIER") and a 1.02 debt service coverage ratio ("DSC").

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Surrebuttal Schedule CSB-1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION		[A] STAFF DIRECT ORIGINAL COST With RAC		[B] COOPERATIVE REBUTTAL ORIGINAL COST With RAC		[C] STAFF SURREBUTTAL ORIGINAL COST With RAC
1	Adjusted Operating Income (Loss)	$	(227,058)	$	2,480,064	$	2,480,064
2	Depreciation and Amortization	$	6,852,107	$	4,144,985	$	4,144,985
3	Income Tax Expense		-		-		-
4	Interest Expense on Long-term Debt	$	5,302,088	$	5,302,088	$	5,302,088
5	Principal Repayment	$	7,358,610	$	7,358,610	$	7,358,610
6	**Recommended Increase in Operating Revenue**	**$**	**3,666,668**	**$**	**3,666,668**	**$**	**3,666,668**
7	Percent Increase (Line 6 / Line 8)		**14.58%**		**14.58%**		**14.58%**
8	Network Service and Other Revenue	$	25,148,196	$	25,148,196	$	25,148,196
9	Regulatory Asset Charge ("RAC")	$	-	$	-	$	-
10	Adjusted Test Year Operating Revenue	$	25,148,196	$	25,148,196	$	25,148,196
11	**Total Annual Operating Revenue**	**$**	**28,814,864**	**$**	**28,814,864**	**$**	**28,814,864**
12	**Operating Margin**	**$**	**3,439,610**	**$**	**6,146,732**	**$**	**6,146,732**
13	Net Margin	$	746,290	$	893,486	$	893,486
14a	Normalized RAC Revenue, Non-operating						
14b	Normalized RAC Revenue	$	2,559,926	$	2,559,926	$	2,559,926
14c	Normalized RAC Expense	$	-	$	2,559,926	$	2,559,926
14d	Net Normalized RAC Margin	$	2,559,926	$	-	$	-
15	Total Operating Revenue and RAC Revenue (L12 + L14b)	$	5,999,536	$	8,706,658	$	8,706,658
16	Cooperative Net TIER (L4+L13) / L4		N/A		1.17		N/A
17	**Staff Operating TIER (L3+L12+L14) / L4**		**1.13**		**1.16**		**1.16**
18	Cooperative DSC (L2+L4+L13+L14b)/(L4+L5)		N/A		1.02		N/A
19	**Staff DSC (L2+L3+L12+L14)/(L4+L5)**		**1.02**		**1.02**		**1.02**
20	**Adjusted Rate Base**	**$**	**76,345,655**	**$**	**76,345,655**	**$**	**76,345,655**
21	Rate of Return (L12 / L20)		4.51%		8.05%		8.05%

References:
Column [A]: Brown, Direct Testimony, Schedule CSB-1
Column [B]: Pierson, Rebuttal Testimony, Exhibit GEP-2
Column [C]: Surrebuttal Testimony

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Surrebuttal Schedule CSB-2

RATE BASE - ORIGINAL COST

LINE NO.		[A] STAFF DIRECT	[B] ADJUSTMENTS	[C] STAFF SURREBUTTAL
1	Plant in Service	$ 131,516,270	$ -	$ 131,516,270
2	Less: Accumulated Depreciation	(55,798,589)	-	(55,798,589)
3	Net Plant in Service	$ 75,717,681	$ -	$ 75,717,681
	LESS:			
4	Advances in Aid of Construction (AIAC)	$ -	$ -	$ -
5	Contributions in Aid of Construction (CIAC)	$ -	$ -	$ -
6	Less: Accumulated Amortization	-	-	-
7	Net CIAC	-	-	-
8	Total Advances and Contributions	$ -	$ -	$ -
9	Member Advances	$ (228,188)	$ -	$ (228,188)
	ADD:			
10	Working Capital	$ 856,162	$ -	$ 856,162
11	Plant Held for Future Use	$ -	$ -	$ -
12	Deferred Debits	$ -	$ -	$ -
13	**Total Rate Base**	$ 76,345,655	$ -	$ 76,345,655

References:
Column [A], Brown, Direct Testimony Schedule CSB-4
Column [B], Brown, Direct Testimony Schedule CSB-4
Column [C]: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Surrebuttal Schedule CSB-3

OPERATING INCOME - TEST YEAR AND STAFF RECOMMENDED

LINE NO.	DESCRIPTION	[A] STAFF DIRECT	[B] ADJUSTMENTS	[C] STAFF SURREBUTTAL	[D] STAFF PROPOSED CHANGES	[E] STAFF RECOMMENDED
1	*REVENUES:*					
2	Network Transmission Serv & Other Revenue	$ 17,530,656	$ -	$ 17,530,656	$ 3,666,668	$ 21,197,324
	Point-to-Point Revenues	7,617,540	-	7,617,540		$ 7,617,540
3	Regulatory Asset Charge	-	-	-	-	-
4	Total Electric Transmission Revenue	$ 25,148,196	$ -	$ 25,148,196	$ 3,666,668	$ 28,814,864
5	*EXPENSES:*					
6	Energy	$ 2,541,334	$ -	$ 2,541,334	$ -	$ 2,541,334
7	Transmission	7,535,913	-	7,535,913	-	7,535,913
8	Administrative and General	3,730,586	-	3,730,586	-	3,730,586
9	Maintenance	2,429,390	-	2,429,390	-	2,429,390
10	Maintenance - General Plant	79	-	79	-	79
11	Depreciation and Amortization	6,852,107	(2,707,122)	4,144,985	-	4,144,985
12	ACC Gross Revenue Taxes	-	-	-	-	-
13	Property Taxes	2,285,845	-	2,285,845	-	2,285,845
14	Income Taxes	-	-	-	-	-
15	**Total Operating Expenses**	$ 25,375,254	$ (2,707,122)	$ 22,668,132	$ -	$ 22,668,132
16	**Operating Margin Before Interest on L.T.- Debt**	$ (227,058)	$ 2,707,122	$ 2,480,064	$ 3,666,668	$ 6,146,732
17	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***					
18	Interest on Long-term Debt	$ 5,302,088	$ -	$ 5,302,088	$ -	$ 5,302,088
19	Other Interest & Other Dedcutions	232,030	-	232,030	-	232,030
20	**Total Interest & Other Deductions**	$ 5,534,118	$ -	$ 5,534,118	$ -	$ 5,534,118
21	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	$ (5,761,176)	$ 2,707,122	$ (3,054,054)	$ 3,666,668	$ 612,614
22	***NON-OPERATING MARGINS***					
23	Interest Income	$ 172,901	$ -	$ 172,901	$ -	$ 172,901
24	Other Non-operating Income	107,971	-	$ 107,971	$ -	$ 107,971
25	**Total Non-Operating Margins**	$ 280,872	$ -	$ 280,872	$ -	$ 280,872
26	***REGULATORY ASSET CHARGE***					
27	**Regulatory Asset Charge Revenue**	$ 2,559,926	$ -	$ 2,559,926	$ -	$ 2,559,926
28	**Regulatory Asset Amortization Expense**	$ -	$ 2,559,926	$ 2,559,926	$ -	$ 2,559,926
29	**Total Regulatory Asset Charge**	$ 2,559,926	$ (2,559,926)	$ 0	$ -	$ 0
30	***NET MARGINS (LOSS)***	$ (2,920,378)	$ 147,196	$ (2,773,182)	$ 3,666,668	$ 893,486

31 References:
32 Column (A): Brown Direct Testimony, Schedule CSB-9
33 Column (B): Surrebuttal Schedule CSB-4
34 Column (C): Column (A) + Column (B)
35 Column (D): Surrebuttal Schedules CSB-1
36 Column (E): Column (C) + Column (D)

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Surrebuttal Schedule CSB-4

TEST YEAR OPERATING INCOME - STAFF DIRECT AND SURREBUTTAL

LINE NO.	DESCRIPTION	[A] STAFF DIRECT	[B] ADJ #1 Regulatory Asset Charge Revenue	[C] STAFF SURREBUTTAL
			Ref: Surrebuttal Sch CSB-5	
	REVENUES:			
1	Network Transmission Service	$ 13,104,192	$ -	$ 13,104,192
2	Point to Point	7,617,540	-	7,617,540
3	Total Electric Revenue	$ 20,721,732	$ -	$ 20,721,732
4	Load Dispatch and System Control	$ 2,824,224	$ -	$ 2,824,224
5	Direct Access Facilities	515,580	-	515,580
6	Regulatory Asset Charge	-	-	-
7	Other Operating Revenue	413,318	-	413,318
8	Ancilliary Services From AEPCO	-	-	-
9	Special Contracts	673,342	-	673,342
10	**Total Revenues**	$ 25,148,196	$ -	$ 25,148,196
	OPERATING EXPENSES:			
11	Energy	$ 2,541,334	$ -	$ 2,541,334
12	Transmission	7,535,913	-	7,535,913
13	Administrative and General	3,730,586	-	3,730,586
14	Maintenance	2,429,390	-	2,429,390
15	Maintenance - General Plant	79	-	79
16	Depreciation and Amortization	6,852,107	(2,707,122)	4,144,985
17	ACC Gross Revenue Taxes	-	-	-
18	Other Taxes	2,285,845	-	2,285,845
19	Income Taxes	-	-	-
20	**Total Operating Expenses**	$ 25,375,254	$ (2,707,122)	$ 22,668,132
21	**Operating Margin Before Interest on L.T.- Debt**	$ (227,058)	$ 2,707,122	$ 2,480,064
23	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***			
24	Interest on Long-term Debt	$ 5,302,088	$ -	$ 5,302,088
25	Other Interest & Other Dedcutions	232,030	-	232,030
26	**Total Interest & Other Deductions**	$ 5,534,118	$ -	$ 5,534,118
27	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	$ (5,761,176)	$ 2,707,122	$ (3,054,054)
28	***NON-OPERATING MARGINS***			
29	Interest Income	$ 172,901	$ -	$ 172,901
30	Other Non-operating Income	107,971	-	107,971
31	**Total Non-Operating Margins**	$ 280,872	$ -	$ 280,872
32	***REGULATORY ASSET CHARGE***			
33	Regulatory Asset Charge Revenue	$ 2,559,926	$ -	$ 2,559,926
34	Regulatory Asset Amortization Expense	$ -	$ 2,559,926	$ 2,559,926
	Total Regulatory Asset Charge	$ 2,559,926	$ (2,559,926)	$ 0
33	***NET MARGINS (LOSS)***	$ (2,920,378)	$ 147,196	$ (2,773,182)

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Surrebuttal Schedule CSB-5

OPERATING INCOME ADJUSTMENT NO. 1 - REGULATORY ASSET CHARGE

LINE NO.	DESCRIPTION	[A] STAFF DIRECT	[B] ADJUSTMENTS	[C] STAFF SURREBUTTAL
1	Revenue	$ 25,148,196	$ -	$ 25,148,196
2	Regulatory Asset Charge	$ -	$ -	$ -
3	Total Revenue	$ 25,148,196	$ -	$ 25,148,196
4	Expense	$ 22,668,132	$ -	$ 22,668,132
5	Regulatory Asset Charge Amortization Exp	$ 2,707,122	$ (2,707,122)	$ -
6	Total Expenses	$ 25,375,254	$ (2,707,122)	$ 22,668,132
7	Operating Margin Before Interest	$ (227,058)	$ 2,707,122	$ 2,480,064
8	Total Interest	$ 5,534,118	$ -	$ 5,534,118
9	Margins After Interest Expense	$ (5,761,176)	$ 2,707,122	$ (3,054,054)
10	Non-Operating Margins	$ 280,872	$ -	$ 280,872
11	Normalized Regulatory Asset Charge Rev	$ 2,559,926	$ -	$ 2,559,926
12	Normalized Regulatory Asset Charge Amort Exp	$ -	$ 2,559,926	$ 2,559,926
13	Net Margin	$ (2,920,378)	$ 147,196	$ (2,773,182)

CALCULATION OF NORMALIZED REGULATORY ASSET CHARGE

	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
13		Total kWhs		Total kWhs
14	Anza	44,660,813	-	44,660,813
15	Duncan	26,782,590	-	26,782,590
16	Graham	136,552,300	-	136,552,300
17	Mohave 1	611,433,890	-	611,433,890
18	Sulphur	662,992,990	-	662,992,990
19	TRICO (See Note Below)	437,521,797	-	437,521,797
20		1,919,944,380		1,919,944,380
21	Regulatory Asset Charge	$ 0.00141	$ (0.00008)	$ 0.00133
22	**Regulatory Asset Charge (L8 x L9)**	$ 2,707,122	(147,196)	$ 2,559,926

23			RAC
24			Decision No.62758
25		2004 RAC	$ 0.00137
26		2005 RAC	$ 0.00133
27	**Note:**	2006 RAC	$ 0.00130
28	The Cooperative filed 437,520,942 kWhs.		$ 0.00400
29	Staff used the Cooperative's actual kWhs	Divided by	3
30	of 437,521,797 to reconcile to the $2,707,122		$ 0.00133
31	in RAC revenue shown on Schedule C1, Page 3, Line 6		

32 References:
33 Column A: Direct Testimony, CSB
34 Column B: Surrebuttal Testimony, CSB
35 Column C: Column [A] + Column [B]

RAMIREZ

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01773A-04-0527

SURREBUTTAL

TESTIMONY

OF

ALEJANDRO RAMIREZ

PUBLIC UTILITIES ANALYST III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 4, 2005

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SCHEDULES

EXECUTIVE SUMMARY
SOUTHWEST TRANSMISSION COOPERATIVE, INC.
DOCKET NO. E-01773A-04-0527

The surrebuttal testimony of Staff witness Alejandro Ramirez addresses the following issues:

Operating Income, TIER and DSC Ratios – Staff recommends operating revenues no less than the $28,814,864 proposed by Southwest Transmission Cooperative, Inc. ("SWTCO" or "Applicant"). SWTCO's proposed revenues and the Regulatory Asset Charge ("RAC") would provide a times interest earned ratio ("TIER") of 1.64 and a debt service coverage ("DSC") ratio of 1.02. The Applicant's proposed revenue barely provides sufficient internally generated cash flow to meet its debt service obligations.

Capital Structure – Staff recommends that the Applicant improve its equity position to 30 percent of the capital structure in a reasonable timeframe.

Staff also recommends that the Commission adopt a patronage distribution restriction for SWTCO that is no less restrictive than the Applicant's existing debt covenants.

Staff further recommends that the Commission require SWTCO to file another rate case within at most three (3) to five (5) years of the effective fate of a decision in this proceeding.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Alejandro Ramirez. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Are you the same Alejandro Ramirez who previously filed direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of this surrebuttal testimony is to respond to the rebuttal testimonies of Mr. Minson and Mr. Pierson. I also present Staff's position in regard to the Applicant's proposed operating income, times interest earned ratio ("TIER"), debt service coverage ration ("DSC") and SWTCO's equity position.

I. UPDATED OPERATING REVENUES RECOMMENDATION

Q. What is Staff's updated recommended operating income for the Applicant?

A. Staff recommends an operating income of no less than $6,146,732, which is the same operating income that would result from the updated revenues proposed in SWTCO's rebuttal testimony.

Q. What TIER and DSC ratios would result from Staff's minimum recommended operating income of $6,146,732?

A. An operating income of $6,146,732 would produce a 1.16 TIER and a 0.81 DSC without the Regulatory Asset Charge ("RAC") and a 1.64 TIER and a 1.02 DSC with the RAC.

Q. Do you have any comments on SWTCO's updated recommended operating income of $6,146,732?

A. Yes. Staff is still concerned with the Applicant's capacity to service its current outstanding debt, finance future capital projects, and improve its equity position.

Q. What TIER and DSC ratio is the Applicant claiming would result from SWTCO's updated proposed revenues?

A. SWTCO claims that its updated proposed revenues of $28,814,864 would produce a 1.17 TIER and a 1.02 DSC.

Q. Why are these ratios different from Staff's TIER and DSC?

A. Staff calculates TIER and DSC ratios differently from SWTCO [which calculates the TIER and DSC in the same manner as the Rural Utility Service ("RUS")]. SWTCO takes into account non-operating revenues when calculating the TIER and DSC while Staff does not. Staff does not take into account non-operating revenues when calculating TIER and DSC ratios because those revenues are not the direct result of SWTCO's regulated activities. Staff cannot foretell whether these non-operating revenues will continue in the future. A decrease in non-operating revenues may negatively impact SWTCO's ability to service its debt; therefore, SWTCO's TIER and DSC calculations provide a less reliable basis for determining debt service capacity.

Q. Why is Staff concerned with SWTCO's capacity to service its current outstanding debt?

A. Staff is concerned with SWTCO's capacity to service its current outstanding debt because the Applicant's proposed operating income, including the RAC, would result in a 1.64 TIER and a 1.02 DSC (Staff's calculated TIER and DSC). As stated in Staff's direct testimony, the DSC ratio represents the number of times internally generated cash will cover payments on both interest and principal. A Staff DSC equal to 1.02 barely covers SWTCO's current debt service. If there is no change from the assumptions built into recommended rates, the Applicant can cover both its principal and interest payments. However, any detrimental change (even slight) in the economic environment resulting in erosion of SWTCO's operating or non-operating revenue or increasing expenses would adversely affect the Applicant's capacity to service its current debt obligations.

Q. Why is Staff concerned with SWTCO's capacity to finance future capital projects?

A. SWTCO's capacity to finance future capital projects may be negatively affected given that—holding everything else equal—additional financing for capital projects may result in a DSC less than 1.00. A DSC less than 1.00 means insufficient cash flow is generated from operations to service existing debt obligations. The Applicant has requested the Commission to authorize SWTCO to incur additional debt financing for approximately $6 million (Docket No. E-04100A-05-0151). SWTCO may not be able to service this additional debt with its proposed revenues alone. In addition, SWTCO's capital structure is highly leveraged; therefore, not consistent with sound financial practices. Staff will recommend denial of this financing unless SWTCO modifies its revenue request. In addition, any other future debt financing will be seriously compromised given the Applicant's proposed revenues.

Q. Will SWTCO's proposed operating income resolve its current financial situation?

A. SWTCO's proposed operating revenues may help mitigate the Applicant's immediate financial problems, but SWTCO's proposal fails to provide any solid solution for the long-run.

Q. What is Staff's current position on the Applicant's updated proposed operating income?

A. Staff recommends that the Commission approve operating revenues for SWTCO that would result in an operating income of no less of $6,146,732 (which is the same operating income that the Applicant is requesting). However, Staff expects the Applicant to address its precarious proposed revenue requirement soon. SWTCO must address this situation in the very near future because the proposed revenue provides for virtually no current borrowing capacity, severely limits future borrowing capacity and does little to improve its highly leveraged capital structure.

II. COMMENTS ON MR. MINSON'S REBUTTAL TESTIMONY

Q. Do you have any comments in regard to Mr. Minson's recommended DSC of 1.02 as the basis to calculate the proposed revenue levels?

A. Yes. Although RUS may provide additional financing to SWTCO if the Applicant's updated proposed revenues are approved by the Commission (given that the proposed revenues result in a 1.02 RUS DSC with RAC), SWTCO's capacity to service its debt payments will be minimal, leaving no cushion for unexpected events. The Applicant may find that its updated proposed revenues are insufficient to support any additional debt financing needed for capital improvements.

Q. Does Mr. Minson contest Staff's recommendation to improve SWTCO's equity position?

A. While Mr. Minson agrees with Staff that the Applicant should continue to build its equity position, he disagrees with Staff's recommendation that SWTCO should increase its equity position to 30 percent of the capital structure.

Q. Does Mr. Minson recommend a specific equity position goal for the Applicant?

A. No. Mr. Minson's opinion is that an equity position of 30 percent is simply too high.

Q. What is Staff's position in regard to SWTCO's equity position?

A. Staff's position is that SWTCO should improve its equity position to at least 30 percent. Staff's position reflects prior a Commission decision (Decision No. 64991, dated June 26, 2002) and SWTCO's need to achieve greater financial flexibility. Also, and article published by Fitch Ratings, a well known rating agency, stated that an equity-to-capitalization ratio between 25 to 30 percent is adequate for a generation and transmission cooperative (See Attachment 1).

Q. Does Mr. Minson take any position in regard to Staff's recommendation of restricting future patronage distributions until the Applicant has achieved a 30 percent capital structure?

A. Yes. Mr. Minson states that SWTCO does not plan, for the foreseeable future, to make any patronage distributions. However, Mr. Minson proposes that if the Commission places any restriction on the patronage distributions, it should be the same restriction presented by the Applicant's debt covenants.

Q. Does Staff have any comments on the restriction of patronage distributions?

A. Yes. Instead of distributing patronage dividends, the Applicant could use those funds to fund, in full or at least partially, future capital projects, thereby increasing its equity position. As mentioned earlier in this testimony, Staff is concerned with SWTCO's current and future borrowing capacity. Staff supports the Commission adopting a patronage distribution restriction for SWTCO that is in accordance with, or even more restrictive than, the Applicant's existing debt covenants.

Q. Do you have any other recommendations for SWTCO?

A. Yes. Given that the Applicant agrees with Staff that SWTCO needs to increase its equity position, but has not shown any specific plan or target to accomplish it, Staff recommends that the Commission require SWTCO to file an equity improvement plan by December 31, 2005. Staff also recommends that the Commission require SWTCO to file a status report with Director of the Utilities Division by March 30 each year showing its equity position and changes from the prior year. Staff strongly recommends that SWTCO consider filing rate cases more frequently. Staff further recommends that the Commission require SWTCO to file another rate case within at most three (3) to five (5) years after the effective date of an order in this proceeding.

CONCLUSION

Q. What is Staff's recommended operating income for SWTCO?

A. Staff recommends an operating income for SWTCO of no less than $6,146,732. Staff is concerned with the Applicant's current and future capacity to service its debt. In addition, Staff is also concerned with the Applicant's borrowing capacity.

Staff further recommends that the Commission require SWTCO to improve its equity position to at least 30 percent. Staff also recommends that the Commission adopt a patronage distribution restriction for SWTCO that is no less restrictive than the Applicant's existing debt covenants.

Staff further recommends that the Commission require SWTCO to docket an equity improvement plan by December 31, 2005.

Staff further recommends that the Commission require SWTCO to docket a calendar year status report with Director of the Utilities Division by March 30 each year showing its equity position and changes from the prior year.

Staff further recommends that the Commission require SWTCO to file another rate case within at most three (3) to five (5) years of the effective fate of a decision in this proceeding.

Q. Does this conclude your surrebuttal testimony?

A. Yes it does.

SWTCO'S TIER and DSC With Staff's Recommended Rates[1]

1	Operating Income	$	6,146,732	**TIER Without RAC**	
2	Regulatory Asset Charge ("RAC")	$	2,559,926	[1+5] ÷ [7]	1.16
3	Total Regulated Revenues	$	8,706,658	**TIER With RAC**	
4	Depreciation & Amort.	$	4,144,985	[3+5] ÷ [7]	1.64
5	Income Tax Expense	$	-		
6					
7	Interest Expense	$	5,302,088	**DSC Without RAC**	
8	Repayment of Principal	$	7,358,610	[1+4+5] ÷ [7+8]	0.81
9				**DSC With RAC**	
10				[3+4+5] ÷ [7+8]	1.02

[1] The amounts reflect Staff's pro forma adjustments and Staff's minimum recommended revenue

Fitch Initiates Coverage of Golden Spread Electric Cooperative with 'A-' Rating

02 Mar 2005 4:14 PM (EST)

Fitch Ratings-New York-March 2, 2005: Fitch Ratings assigns an initial senior secured rating of 'A-' to Golden Spread Electric Cooperative, Inc.'s (Golden Spread) $55 million 2005 private placement. The Rating Outlook is Stable. Proceeds will be used to repay Golden Spread for the acquisition and construction costs incurred to date and to complete the construction of a 145-mw gas-fired combustion turbine peaking unit. The 2005 financing will be priced in March 2005 with La Salle Capital as sole placement agent.

The foundation of Golden Spread's long-term rating derives from a pledge of revenues from the company's full-requirement contracts with its 16 members through the life of the bonds. In addition, bondholders will be secured by a lien on the 145-mw peaking units as well as surplus cash from Golden Spread's sale of energy from current and future affiliated power projects. Other positive credit factors include favorable intermediate-term partial-requirement power supply arrangements with Southwestern Public Service Company (SPS), a wholly owned subsidiary of Xcel Energy, experienced management and consultants, and a solid financial profile.

Credit concerns include Golden Spread's need to develop power supply to replace its SPS partial-requirement agreement that expires in 2012, its higher than average concentration of commercial and irrigation customers among its members' retail loads (representing more than 70% of member revenues), the need to maintain adequate liquidity and financial margins in the future, and lean management team.

In 1984, 11 distribution utilities formed Golden Spread to consolidate their interests and provide power supply alternatives to SPS. In this role, Golden Spread negotiated a partial-requirement power supply arrangement and dispatch arrangement (both of which expire in 2012). These arrangements provides Golden Spread the flexibility to utilize at its discretion over 300 mw of SPS resources (with a fuel mix of 2/3 coal and 1/3 gas) and the full capacity of the Mustang Station, a 483-mw combined-cycle plant that has been on-line since 2000. As part of the dispatch arrangement with SPS, Golden Spread is able to sell its excess energy from Mustang at favorable rates that help reduce its wholesale cost of power. Fitch views these arrangements as positive and stable factors in Golden Spread's credit profile.

With the forthcoming expiration of the SPS partial-requirement agreement and the need to increase its power supply, Golden Spread is currently developing and implementing a generation expansion program. In the next seven years, Golden Spread's capital expenditures will total over $800 million (funded with approximately 80% debt and 20% cash) to fund various coal and gas-fired generation projects.

The 'A-' rating is based on Golden Spread's solid historical operations, and assumes the cooperative is successful in its implementation of a diversified and adequate power supply portfolio while maintaining sound financial results. Fitch recognizes the majority of the planned projects are in the early stages of development and that Golden Spread could modify its plan as the wholesale market and power supply alternatives change. Fitch is comforted by Golden Spread's track record in developing the Mustang Station and the experience of its management and long-time consultants. Nevertheless, unexpected delays or substantial project cost increases above projections could become a negative credit factor should they compromise Golden Spread's financial strength or if they significantly affect the members' retail customers' cost of power and financial viability.

Although the new projects will substantially increase Golden Spread's leverage and annual debt service requirements, current and projected ratios are well above average for the rating category and include 2003 debt service coverage of 2.3 times (x) and equity-to-capitalization of 31%. Unaudited results for fiscal-year 2004 are in-line with historical levels. For the future, management expects to maintain a minimum debt service coverage ratio of 1.5x and equity-to-capitalization ratios between 25%-30%, which is good for a generation and transmission cooperative.

Golden Spread's future generation units could be funded as separate projects whereby a portion of a project's cash and equity would be segregated from Golden Spread and the 2005 bondholders. Fitch does not consider this risk as meaningful, since each of the projects would likely be serving a majority, if not all members, and operating margins and cash reserves at any individual project should not be significant.

Golden Spread has over $20 million in cash reserves and also maintains $110 million in available liquidity facilities. In aggregate, this liquidity provides over six months of operating expenses. In addition to these funds, Golden Spread has approximately $40 million in cash that is pledged to a future power project. Further bolstering its liquidity profile, Fitch views positively Golden Spread's competitive wholesale rates and a structure that automatically adjusts for changes in fuel and purchased power costs on a monthly basis. Golden Spread plans to use a portion of its current and projected cash balances over the next few years to partially fund the costs of its various planned generation projects. With lower levels of cash projected during that period, Fitch will look for Golden Spread to maintain sufficient levels of liquidity with available lines of credit and conservative revenue requirement projections.

Golden Spread is a not-for-profit generation and transmission cooperative providing electric service to 16 distribution cooperatives. Fifteen members are located in Texas' Panhandle, South Plains and Edward Plateau regions and one member is located in the Oklahoma Panhandle region. The service area of Golden Spread's Texas members represent approximately 24% of the land mass of Texas. In 2003, Golden Spread's membership increased to 16 members from the original 11. The 16 distribution members serve nearly 200,000 customers.

In 2004, Golden Spread's total revenues were almost $411 million, with 66% representing revenues under long-term member contracts and 34% from sales to SPS.

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CASPER

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A RATE INCREASE	))))	DOCKET NO. E-04100A-04-0527

SURREBUTTAL

TESTIMONY

OF

ERIN CASPER

PUBLIC UTILITIES ANALYST IV

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 4, 2005

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EXECUTIVE SUMMARY
SOUTHWEST TRANSMISSION COOPERATIVE, INC.
DOCKET NO. E-04100A-04-0527

The following surrebuttal testimony presents Staff's response to Southwest Transmission Cooperative, Inc.'s ("Southwest Transmission" or "Cooperative") rebuttal testimony regarding the rate design and the loss of revenues associated with the termination of Morenci Water & Electric's 60 MW firm point-to-point contract effective January 1, 2006.

Staff provides updated rate recommendations using Staff's revised revenue requirement to be effective through December 31, 2005. Staff also presents a second set of recommended rates consistent with its recommendation that, effective January 1, 2006, Southwest's rates should increase to reflect the loss of revenue resulting from the termination of the Morenci Water & Electric 60 MW firm point-to-point contract.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Erin Casper. I am a Public Utility Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington, Phoenix, Arizona 85007.

Q. Did you file direct testimony in this matter?

A. Yes. On February 23, 2005, I submitted direct testimony that addressed the cost allocation and rate recommendations for Southwest Transmission Cooperative's ("Southwest" or "Southwest Transmission" or "Cooperative") application for a general rate increase.

Q. What is the purpose of this surrebuttal testimony?

A. I will provide Staff's updated rate recommendations to be effective through December 31, 2005 using Staff's revised revenue requirement described in the surrebuttal testimony of Staff Witness Crystal Brown. Secondly, consistent with Staff Witness Brown's recommendation that, effective January 1, 2006, Southwest's rates should increase to reflect the loss of revenue due to the termination of the Morenci Water & Electric ("MW&E") 60 MW firm point-to-point contract, I will provide Staff's recommended rates to go into effect January 1, 2006.

SUMMARY OF RECOMMENDATIONS

Q. In general, how did Staff calculate the revised recommended rates to be effective through December 31, 2005?

A. Staff calculated revised rates consistent with the methodology described in the direct testimony. While recommending the same overall revenue requirement of $28,814,864 for Southwest Transmission Company, in its surrebuttal testimony, Staff proposed some changes to depreciation expenses and operating margin that require Staff to make minor modifications to the recommended rates. These changes yield a slightly lower point-to-point rate for Morenci Water & Electric (effective through December 31, 2005) and a slightly higher Network Services Revenue Requirement.

Q. Please describe Staff's recommendation with respect to Southwest's proposal to phase in rates to reflect revenue loss associated with the termination of the MW&E 60 MW firm point-to-point contract on January 1, 2006.

A. Southwest has requested that the Commission authorize initial rates to be effective through December 31, 2005 followed by a second set of rates to reflect the termination of the MW&E 60 MW firm point-to-point contract to be effective beginning January 1, 2006. Staff recommends that the Commission approve a rate phase-in plan as set forth on Schedule EEC-1. Both sets of recommended rates are designed to recover Staff's recommended revenue requirement of $28,814,864.

Q. In general, how did Staff calculate the revised recommended rates to go into effect January 1, 2006 following the termination of the MW&E 60 MW firm point-to-point contract?

A. Staff adjusted the values for the system coincident peak demand ("1CP"), system average monthly peak demand ("12CP"), and point-to-point megawatts that reflect the loss of 60 MW of point-to-point load. Staff then calculated recommended rates to be effective beginning January 1, 2006 consistent with the methodology described in the direct testimony and used to calculate recommended rates to be in effect through December 31, 2005.

RATES EFFECTIVE THROUGH DECEMBER 31, 2005

Q. What is the Cooperative's revised proposed rate design to be effective through December 31, 2005?

A. Southwest Transmission has proposed the following revised rates to be effective through December 31, 2005:

Transmission Service	Present Rate	Cooperative Rebuttal Rate	% Change From Present
Firm Point-to-Point ($ / kW)	$2.805	$3.022	7.45%
Non-Firm Point-to-Point ($ / kW)	$2.805	$3.022	7.45%
Firm Network Service - Annual Rev. Req.	$13,104,193	$17,046,503	26.30%
Firm Network Service - Monthly Rev. Req.	$1,092,016	$1,420,542	26.30%
Schedule 1 ($ / kW)	$0.422	$0.289	-37.86%
Schedule 2 – Point-to-Point ($ / kW)	$0.056	$0.064	13.35%
Schedule 2 – Network ($ / kW)	$0.065	$0.080	20.76%
Schedule 3 ($ / kW)	$0.518	$0.428	-19.09%
Schedule 4 - +/- 1.5% Imbalance ($ / MW)	$23.25	$0.0203	-12.39%
Schedule 5 ($ / kW)	$0.685	$0.646	-5.80%
Schedule 6 ($ / kW)	$0.343	$0.417	19.54%

Q. What is Staff's revised recommended rate design to be effective through December 31, 2005?

A. Based on Staff's overall revised revenue requirement, Staff recommends the following rates for Southwest Transmission Cooperative to be effective through December 31, 2005:

Transmission Service	Present Rate	Staff Surrebuttal	% Change From Present	% Change From Cooperative Rebuttal
Firm Point-to-Point ($ / kW)	$2.805	$3.022	7.45%	0.0%
Non-Firm Point-to-Point ($ / kW)	$2.805	$3.022	7.45%	0.0%

Firm Network Service - Annual Rev. Req.	$13,104,193	$17,048,663	26.31%	0.013%
Firm Network Service - Monthly Rev. Req.	$1,092,016	$1,420,722	26.31%	0.013%
Schedule 1 ($ / kW)	$0.422	$0.289	-37.86%	0.0%
Schedule 2 – Point-to-Point ($ / kW)	$0.056	$0.072	25.13%	11.8%
Schedule 2 – Network ($ / kW)	$0.065	$0.090	32.54%	11.8%
Schedule 3 ($ / kW)	$0.518	$0.444	-15.42%	3.7%
Schedule 4 - +/- 1.5% Imbalance ($ / MW)	$23.25	$0.0204	-12.00%	0.4%
Schedule 5 ($ / kW)	$0.685	$0.671	-2.01%	3.8%
Schedule 6 ($ / kW)	$0.343	$0.433	23.30%	3.8%

Q. Explain the differences in Staff's revised recommended rate design versus Staff's originally filed recommended rate design for rates to be effective through December 31, 2005.

A. Although Staff recommended the same overall revenue requirement of $28,814,864 for Southwest Transmission Company as in its direct testimony, Staff's surrebuttal testimony proposes changes to depreciation expenses and operating margin that yield an increased rate of return on rate base. The rate of return is used in the calculation of the discount to the Morenci Water & Electric point-to-point rate. The larger rate of return produces a slightly larger discount, thus, a lower point-to-point rate for MW&E. The lower rate for MW&E yields slightly lower total point-to-point revenues. Staff's revised recommended point-to-point rate for MW&E is $3.004/kW as compared to Staff's original recommendation of $3.007/kW. Schedule EEC-3 shows the revised calculation of the discounted point-to-point rate for MW&E.

Due to the decreased point-to-point revenues, the Network Services Revenue Requirement, which is equal to the Total Revenue Requirement less Other Revenues less Schedule 1 Revenues less Point-to-Point Revenues, must increase slightly. Staff's revised recommended monthly Network Service Revenue Requirement is $1,420,722 as compared to its original recommendation of $1,420,542. Schedule EEC-6 shows the revised calculation for the Network Service Revenue Requirement and Schedule EEC-7 shows the revised estimated allocation of the Network Service Revenue Requirement among the Network Service customers.

Finally, Staff's recommended rates for Ancillary Services Schedules 2-6 have been revised as necessary to account for minor revisions to Staff's recommended operating expenses and rate of return for AEPCO. Rates for Ancillary Services Schedules 2-6 increased slightly as a result of a slightly higher rate of return on rate base for AEPCO. Schedules EEC-9, EEC-10, and EEC-11 show Staff's revised recommended rates for Ancillary Services Schedules 2-6.

Q. Explain the differences in Staff's revised recommended rate design versus the Cooperative's revised proposed rate design for rates through December 31, 2005.

A. In its rebuttal testimony, Southwest proposed rates equal to those recommended by Staff in its direct testimony. Thus, Staff's revised recommended rates differ from the Cooperative's revised proposed rates as described above.

RATES EFFECTIVE BEGINNING JANUARY 1, 2006

Q. What is the Cooperative's proposed rate design to go into effect January 1, 2006 following the termination of the MW&E 60 MW firm point-to-point contract?

A. Southwest Transmission has proposed the following rates to go into effect following the termination of the MW&E 60 MW firm point-to-point contract:

Transmission Service	Present Rate	Cooperative Rebuttal Rate	% Change From Present
Firm Point-to-Point ($ / kW)	$2.805	$3.334	17.28%

Non-Firm Point-to-Point ($ / kW)	$2.805	$3.334	17.28%
Firm Network Service - Annual Rev. Req.	$13,104,193	$18,792,971	36.06%
Firm Network Service - Monthly Rev. Req.	$1,092,016	$1,566,081	36.06%
Schedule 1 ($ / kW)	$0.422	$0.289	-37.86%
Schedule 2 – Point-to-Point ($ / kW)	$0.056	$0.064	13.35%
Schedule 2 – Network ($ / kW)	$0.065	$0.080	20.76%
Schedule 3 ($ / kW)	$0.518	$0.428	-19.09%
Schedule 4 - +/- 1.5% Imbalance ($ / MW)	$23.25	$0.0203	-12.39%
Schedule 5 ($ / kW)	$0.685	$0.646	-5.80%
Schedule 6 ($ / kW)	$0.343	$0.417	19.54%

Q. What is Staff's recommended rate design to go into effect January 1, 2006 following the termination of the MW&E 60 MW firm point-to-point contract?

A. Based on Staff's overall revised revenue requirement and adjusted values for the system coincident peak demand ("1CP"), system average monthly peak demand ("12CP"), and point-to-point megawatts that reflect the termination of the MW&E 60 MW firm point-to-point contract, Staff recommends the following rates for Southwest Transmission Cooperative to go into effect January 1, 2006:

Transmission Service	Present Rate	Staff Surrebuttal	% Change From Present	% Change From Cooperative Rebuttal
Firm Point-to-Point ($ / kW)	$2.805	$3.334	17.28%	0.0%
Non-Firm Point-to-Point ($ / kW)	$2.805	$3.334	17.28%	0.0%
Firm Network Service - Annual Rev. Req.	$13,104,193	$18,792,971	36.06%	0.0%
Firm Network Service - Monthly Rev. Req.	$1,092,016	$1,566,081	36.06%	0.0%
Schedule 1 ($ / kW)	$0.422	$0.289	-37.86%	0.0%
Schedule 2 – Point-to-Point ($ / kW)	$0.056	$0.078	33.14%	19.78%
Schedule 2 – Network ($ / kW)	$0.065	$0.100	43.08%	22.31%
Schedule 3 ($ / kW)	$0.518	$0.444	-15.42%	3.7%
Schedule 4 - +/- 1.5% Imbalance ($ / MW)	$23.25	$0.0204	-12.00%	0.4%

Schedule 5 ($ / kW)	$0.685	$0.671	-2.01%	3.8%
Schedule 6 ($ / kW)	$0.343	$0.433	23.30%	3.8%

Q. Explain the differences in Staff's revised recommended rate design to be effective through December 31, 2005, and Staff's recommended rate design to go into effect January 1, 2006, following the termination of the MW&E 60 MW firm point-to-point contract.

A. Southwest will lose a total of $2,370,960[1] in annual revenues following the termination of the MW&E 60 MW firm point-to-point contract on January 1, 2006. As a result, Staff has recalculated rates that recognize the loss of this revenue to go into effect beginning January 1, 2006. Schedule EEC-1 shows Staff's recommended rates effective through December 31, 2005, compared to rates effective January 1, 2006. Essentially, Staff recalculated the rates using revised values for the system coincident peak demand ("1CP"), system average monthly peak demand ("12CP"), and point-to-point megawatts that reflect the loss of 60 MW of point-to-point load. The revised billing data, shown on Schedule EEC-12, yield the following results.

Schedule 1 point-to-point revenues decrease as a result of the loss of 60 MW of point-to-point load. The reduction in Schedule 1 revenues effectively increases the Total Transmission Revenue Requirement which is equal to the Total Revenue Requirement less Other Revenues less Schedule 1 Revenues.

The increased Total Transmission Revenue Requirement is divided by the lower system coincident peak demand ("1CP") to derive the higher point-to-point rates shown on

[1] The total revenue loss of $2,370,960 is equal to $2,162,880 in annual point-to-point revenues plus $208,080 in annual Schedule 1 revenues.

Schedule EEC-13. The point-to-point rate increases from \$3.022[2] to \$3.334. The same methodology applies to the calculation of the discounted point-to-point rate for the Town of Thatcher shown on Schedule EEC-14. The discounted point-to-point rate for the Town of Thatcher increases from \$2.605[3] to \$2.878. As calculated on Schedule EEC-15, the total revenues derived from point-to-point service drop from \$8,230,212[4] to \$6,693,984 as a result of the loss of 60 MW of point-to-point load.

As a result of the decrease in point-to-point revenues, the monthly Network Service Revenue Requirement increases from \$1,420,722[5] to \$1,566,081. The Network Service Revenue Requirement, shown on Schedule EEC-16, is equal to the Total Transmission Revenue Requirement less the point-to-point revenues and is allocated among the Network Service customers as shown on Schedule EEC-17.

Finally, Ancillary Service Schedule 2, Cost of Reactive Power (VAR) Production, must be revised to reflect the revised 1CP and 12CP values. The recommended rates for Schedule 2 are shown on Schedule EEC-19.

Q. Explain the differences in Staff's revised recommended rate design versus the Cooperative's revised proposed rate design to go into effect January 1, 2006 following the termination of the MW&E 60 MW firm point-to-point contract.

A. There is only one major difference between Staff's recommended rates and the Cooperative's proposed rates to go into effect beginning January 1, 2006. Southwest did not revise the rate for Ancillary Service Schedule 2, Cost of Reactive Power (VAR) Production, to reflect the changes in the 1CP and the 12CP. Staff finds that it is

[2] Shown on Schedule EEC-2.
[3] Shown on Schedule EEC-4.
[4] Shown on Schedule EEC-5.
[5] Shown on Schedule EEC-6.

appropriate to recalculate the rate for Schedule 2 to reflect the loss of the 60 megawatts associated with the termination of the MW&E firm point-to-point contract and recommends the rates set forth on Schedule EEC-19.

Rates for Ancillary Services Schedules 3-6 do not depend on the billing data for Southwest Transmission Cooperative, and thus, do not need to be revised due to the loss of the MW&E contract. Rates for Ancillary Service Schedules 3-6 effective January 1, 2006 are shown on Schedules EEC-20 and EEC-21.

Q. Does this conclude your testimony?

A. Yes, it does.

Southwest Transmission Cooperative, Inc.
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Comparison of Recommended Rates

Transmission Service	Present Rate	Staff Recommended Effective Through December 31, 2005	% Change from Present	Staff Recommended Effective Beginning January 1, 2006	% Change from Staff Recommended 2005 Rates	% Change from Present
Firm Point-to-Point ($ / kW)	$2.805	$3.022	7.45%	$3.334	9.83%	17.28%
Non-Firm Point-to-Point ($ / kW)	$2.805	$3.022	7.45%	$3.334	9.83%	17.28%
Firm Network Service - Annual Rev. Req.	$13,104,193	$17,048,663	26.31%	$18,792,971	9.74%	36.06%
Firm Network Service - Monthly Rev. Req.	$1,092,016	$1,420,722	26.31%	$1,566,081	9.74%	36.06%
Schedule 1 ($ / kW)	$0.422	$0.289	-37.86%	$0.289	0.00%	-37.86%
Schedule 2 – Point-to-Point ($ / kW)	$0.056	$0.072	25.13%	$0.078	8.00%	33.14%
Schedule 2 – Network ($ / kW)	$0.065	$0.090	32.54%	$0.100	10.54%	43.08%
Schedule 3 ($ / kW)	$0.518	$0.444	-15.42%	$0.444	0.00%	-15.42%
Schedule 4 - +/- 1.5% Imbalance ($ / MW)	$0.0230	$0.0204	-12.00%	$0.0204	0.00%	-12.00%
Schedule 5 ($ / kW)	$0.685	$0.671	-2.01%	$0.671	0.00%	-2.01%
Schedule 6 ($ / kW)	$0.343	$0.433	23.30%	$0.433	0.00%	23.30%

Southwest Transmission Cooperative, Inc.
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Surrebuttal Schedule EEC-2

Calculation of the Point-to-Point Rate
Recommended Rates Through December 31, 2005

Total Revenue Requirement = O&M + Depr&Amort + Taxes + Operating Margin		
O&M		16,237,302
Depreciation & Amortization		4,144,985
Taxes		2,285,845
Operating Margin		6,146,732
Total Revenue Requirement		**28,814,864**
Less Other Operating Revenues		
Direct Assignment		515,580
Regulatory Asset Charge		-
Other Reveues		413,318
Special Contracts		673,342
Ancillary Service (Schedules 2-6)		-
Total Other Operating Revenues		**1,602,240**
Transmission Revenue Requirement (including Schedule 1)		**27,212,624**
Schedule 1 Revenues	**$ / kW**	
Schedule 1 - PtP Revenue	0.289	790,704
Schedule 1 - Network Services Revenue	0.289	1,143,045
Total Schedule 1 Revenues		1,933,749
Total Transmission Revenue Requirement		**25,278,875**

Point to Point Transmission Serive (1 CP method)

	Revenue Requirement	TY 2003 1 CP (kW)	Annual Rate ($/kW)	Monthly Rate ($/kW)
1 CP Rate - Standard	25,278,875	697,093	$36.26	$3.022

Point-to-Point Service	Standard Ave Montly kW	Standard PTP Rate	Standard PTP Revenute
Jan	163,000	$3.022	$492,586
Feb	163,000	$3.022	$492,586
Mar	163,000	$3.022	$492,586
Apr	163,000	$3.022	$492,586
May	163,000	$3.022	$492,586
Jun	163,000	$3.022	$492,586
Jul	163,000	$3.022	$492,586
Aug	163,000	$3.022	$492,586
Sep	163,000	$3.022	$492,586
Oct	163,000	$3.022	$492,586
Nov	163,000	$3.022	$492,586
Dec	163,000	$3.022	$492,586
Total			**$5,911,032**

Southwest Transmission Cooperative, Inc.
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Calculation of the Discount to the Point-to-Point Rate for Morenci Water & Electric
Recommended Rates Through December 31, 2005

Total Transmission Revenue Requirement	**25,278,875**
Greenlee Transformer Revenue Credit for MW&E	
(Remove Required Revenue Allocated to Greenlee Transformer from Total Transmission Revenue Requirement)	
Net Investement Greenlee Transformer	571,326
Carrying Charge on Investment in Plant*	8.051%
Carrying Cost - Greenlee	45,999
O&M Expenses - Greenlee	100,869
Revenue Requirement Allocated to Greenlee Transformer	146,868
MW&E Transmission Revenue Requirement	**25,132,007**

Point to Point Transmission Serive (1 CP method)

	Revenue Requirement	TY 2003 1 CP (kW)	Annual Rate ($/kW)	Monthly Discount	Monthly Rate ($/kW)
1 CP Rate - MW&E Greenlee Discount	25,132,007	697,093	$36.05	$0.018	$3.004

Point-to-Point Service	MW&E Ave Monthly kW	MW&E Discount PTP Rate	MW&E Discount PTP Revenue
Jan	60,000	$3.004	$180,240
Feb	60,000	$3.004	$180,240
Mar	60,000	$3.004	$180,240
Apr	60,000	$3.004	$180,240
May	60,000	$3.004	$180,240
Jun	60,000	$3.004	$180,240
Jul	60,000	$3.004	$180,240
Aug	60,000	$3.004	$180,240
Sep	60,000	$3.004	$180,240
Oct	60,000	$3.004	$180,240
Nov	60,000	$3.004	$180,240
Dec	60,000	$3.004	$180,240
Total			**$2,162,880**

* The Carrying Cost is equal to Staff's Recommended (Operating Margin / Rate Base)

Southwest Transmission Cooperative, Inc.
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Calculation of the Discount to the Point-to-Point Rate for the Town of Thatcher
Recommended Rates Through December 31, 2005

Total Transmission Revenue Requirement	**25,278,875**
Discount for Town of Thatcher - WAPA Wheeling Expenses	
(Remove WAPA Wheeling Expenses from Total Transmission Revenue Requirement)	
WAPA Wheeling Costs $3,484,188	3,484,188
Town of Thatcher Transmission Revenue Requirement	**21,794,687**

Point to Point Transmission Serive (1 CP method)

	Revenue Requirement	TY 2003 1 CP (kW)	Annual Rate ($/kW)	Monthly Discount	Monthly Rate ($/kW)
1 CP Rate - Thatcher Discount	21,794,687	697,093	$31.27	$0.417	$2.605

Point-to-Point Service	Thatcher Ave Monthly kW	Thatcher Discount PTP Rate	Thatcher Discount PTP Revenue
Jan	4,000	$2.605	$10,420
Feb	4,000	$2.605	$10,420
Mar	4,000	$2.605	$10,420
Apr	4,000	$2.605	$10,420
May	6,000	$2.605	$15,630
Jun	6,000	$2.605	$15,630
Jul	6,000	$2.605	$15,630
Aug	6,000	$2.605	$15,630
Sep	6,000	$2.605	$15,630
Oct	6,000	$2.605	$15,630
Nov	4,000	$2.605	$10,420
Dec	4,000	$2.605	$10,420
Total - Town of Thatcher			**$156,300**

Southwest Transmission Cooperative, Inc.
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Calculation of the Point-to-Point Revenues
Recommended Rates Through December 31, 2005

Point to Point Transmission Serive (1 CP method)

	Revenue Requirement	TY 2003 1 CP (kW)	Annual Rate ($/kW)	*Monthly* Discount	Monthly Rate ($/kW)
1 CP Rate - Standard	25,278,875	697,093	$36.26	$0.000	$3.022
1 CP Rate - Thatcher Discount	21,794,687	697,093	$31.27	$0.417	$2.605
1 CP Rate - MW&E Greenlee Discount	25,132,007	697,093	$36.05	$0.018	$3.004

Point-to-Point Service	Standard Ave Monthly kW	Thatcher Ave Monthly kW	MW&E Ave Monthly kW	Standard PTP Rate	Thatcher Discount PTP Rate	MW&E Discount PTP Rate
Jan	163,000	4,000	60,000	$3.022	$2.605	$3.004
Feb	163,000	4,000	60,000	$3.022	$2.605	$3.004
Mar	163,000	4,000	60,000	$3.022	$2.605	$3.004
Apr	163,000	4,000	60,000	$3.022	$2.605	$3.004
May	163,000	6,000	60,000	$3.022	$2.605	$3.004
Jun	163,000	6,000	60,000	$3.022	$2.605	$3.004
Jul	163,000	6,000	60,000	$3.022	$2.605	$3.004
Aug	163,000	6,000	60,000	$3.022	$2.605	$3.004
Sep	163,000	6,000	60,000	$3.022	$2.605	$3.004
Oct	163,000	6,000	60,000	$3.022	$2.605	$3.004
Nov	163,000	4,000	60,000	$3.022	$2.605	$3.004
Dec	163,000	4,000	60,000	$3.022	$2.605	$3.004

Point-to-Point Service	Standard PTP Revenute	Thatcher Discount PTP Revenue	MW&E Discount PTP Revenue	Total PTP Annual Revenues
Jan	$492,586	$10,420	$180,240	$683,246
Feb	$492,586	$10,420	$180,240	$683,246
Mar	$492,586	$10,420	$180,240	$683,246
Apr	$492,586	$10,420	$180,240	$683,246
May	$492,586	$15,630	$180,240	$688,456
Jun	$492,586	$15,630	$180,240	$688,456
Jul	$492,586	$15,630	$180,240	$688,456
Aug	$492,586	$15,630	$180,240	$688,456
Sep	$492,586	$15,630	$180,240	$688,456
Oct	$492,586	$15,630	$180,240	$688,456
Nov	$492,586	$10,420	$180,240	$683,246
Dec	$492,586	$10,420	$180,240	$683,246
Total Revenues	$5,911,032	$156,300	$2,162,880	$8,230,212

Point-to-Point Revenue Total $8,230,212

Calculation of the Network Service Revenue Requirement
Recommended Rates Through December 31, 2005

Total Revenue Requirement = O&M + Depr&Amort + Taxes + Operating Margin		
O&M		16,237,302
Depr&Amort		4,144,985
Taxes		2,285,845
Operating Margin		6,146,732
Total Revenue Requirement		**28,814,864**
Less Other Operating Revenues		
Direct Assignment		515,580
Regulatory Asset Charge		-
Other Reveues		413,318
Special Contracts		673,342
Ancillary Service (Schedules 2-6)		-
Total Other Operating Revenues		**1,602,240**
Transmission Revenue Requirement (including Schedule 1)		**27,212,624**
Schedule 1 Revenues	**$ / KW**	
Schedule 1 - PtP Revenue	0.289	790,704
Schedule 1 - Network Services Revenue	0.289	1,143,045
Total Schedule 1 Revenues		1,933,749
Total Transmission Revenue Requirement		**25,278,875**
Less: Point-to-Point Revenue Total		**8,230,212**
Network Services Annual Revenue Requirement		**17,048,663**
Network Services Monthly Revenue Requirement		**1,420,722**

Network Services Revenue Requirement	2003 TY Billing Demand kW	Recommended Revenue Requirement Network Service	Average Network Service $/kW
Annual		**17,048,663**	**$4.310**
January	227,326	$1,420,722	$6.250
February	246,798	$1,420,722	$5.757
March	233,791	$1,420,722	$6.077
April	241,243	$1,420,722	$5.889
May	377,915	$1,420,722	$3.759
June	416,091	$1,420,722	$3.414
July	468,093	$1,420,722	$3.035
August	455,578	$1,420,722	$3.119
September	411,003	$1,420,722	$3.457
October	363,220	$1,420,722	$3.911
November	241,090	$1,420,722	$5.893
December	273,026	$1,420,722	$5.204

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Surrebuttal Schedule EEC-7

Estimated Allocation of the Network Service Revenue Requirement*
Recommended Rates Through December 31, 2005

NETWORK CUSTOMERS		January	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total 2003	Average
Anza	2002 kW Demand	6,432	6,084	5,472	5,496	6,660	7,068	8,628	8,400	7,812	5,112	6,324	6,912	80,400	6,700
Anza	Loads 2003	5,436	5,556	6,012	5,496	7,452	7,920	9,516	9,264	7,644	6,708	5,424	6,036	82,464	6,872
Anza	12 Month Rolling Avg	6,617	6,573	6,618	6,618	6,684	6,755	6,829	6,901	6,887	7,020	6,945	6,872	81,319	6,777
Anza	Revenue - 2003 Load	32,081	31,947	32,116	32,331	32,432	32,254	31,798	31,375	30,704	30,556	30,061	29,622	377,275	31,440
Duncan	2002 kW Demand	3,320	2,360	3,440	3,780	5,320	6,040	5,240	5,340	4,840	2,900	3,080	3,460	49,120	4,093
Duncan	Loads 2003	3,000	3,280	3,280	3,420	4,780	5,400	5,180	4,820	5,380	4,600	3,300	3,760	50,200	4,183
Duncan	12 Month Rolling Avg	4,067	4,143	4,130	4,100	4,055	4,002	3,997	3,953	3,998	4,140	4,158	4,183	48,927	4,077
Duncan	Revenue - 2003 Load	19,717	20,138	20,042	20,030	19,676	19,107	18,610	17,973	17,825	18,020	17,999	18,032	227,169	18,931
Graham	2002 kW Demand	14,758	15,023	15,662	20,461	27,751	33,126	33,349	30,972	28,798	16,583	14,149	16,503	267,135	22,261
Graham	Loads 2003	13,710	14,481	15,790	17,075	23,316	31,629	33,111	33,096	29,452	22,775	15,313	14,738	264,486	22,041
Graham	12 Month Rolling Avg	22,174	22,129	22,139	21,857	21,488	21,363	21,343	21,520	21,575	22,091	22,188	22,041	261,906	21,826
Graham	Revenue - 2003 Load	107,506	107,553	107,438	106,780	104,262	102,004	99,380	97,839	96,184	96,153	96,036	95,005	1,216,141	101,345
Mohave 1	2002 kW Demand	71,793	71,893	62,190	94,674	110,200	99,000	116,000	115,000	96,000	79,000	60,296	64,007	1,040,053	86,671
Mohave 1	Loads 2003	60,706	68,839	61,639	64,778	116,000	137,930	130,000	129,000	109,000	112,000	65,082	73,050	1,128,024	94,002
Mohave 1	12 Month Rolling Avg	85,747	85,493	85,447	82,955	83,439	86,683	87,850	89,016	90,100	92,850	93,248	94,002	1,056,829	88,069
Mohave 1	Revenue - 2003 Load	415,730	415,522	414,655	405,267	404,861	413,895	409,054	404,704	401,682	404,143	403,615	405,193	4,898,322	408,193
Sulphur Springs	2002 kW Demand	94,849	93,072	82,413	71,220	103,544	110,561	112,009	107,663	102,241	76,651	75,788	92,659	1,122,670	93,556
Sulphur Springs	Loads 2003	82,360	84,958	82,242	83,467	101,093	112,464	123,813	121,214	108,324	101,850	83,848	96,867	1,182,500	98,542
Sulphur Springs	12 Month Rolling Avg	92,515	91,839	91,825	92,845	92,641	92,800	93,783	94,913	95,419	97,519	98,191	98,542	1,132,832	94,403
Sulphur Springs	Revenue - 2003 Load	448,543	446,367	445,606	453,582	449,512	443,101	436,682	431,511	425,399	424,469	425,009	424,761	5,254,543	437,879
Trico	2002 kW Demand	60,797	59,164	51,292	61,409	79,649	96,441	94,660	92,968	90,421	62,274	45,742	58,683	853,500	71,125
Trico	Loads 2003	48,450	55,671	51,504	52,628	83,909	98,670	109,062	108,124	91,233	84,203	58,199	68,109	909,762	75,814
Trico	12 Month Rolling Avg	70,096	69,805	69,823	69,091	69,446	69,632	70,832	72,095	72,163	73,990	75,028	75,814	857,813	71,484
Trico	Revenue - 2003 Load	339,849	339,275	338,835	337,534	336,965	332,479	329,814	327,773	321,715	322,054	324,750	326,792	3,977,833	331,486
AEPCO Bundled	2002 kW Demand	8,000	7,880	7,880	7,620	7,360	6,920	7,320	6,740	6,700	6,760	6,700	6,740	86,620	7,218
Power Sales using	Loads 2003	6,320	6,220	5,980	6,260	6,780	6,900	6,360	5,920	6,100	5,700	2,780	2,660	67,980	5,665
Network Service	12 Month Rolling Avg	7,078	6,940	6,782	6,668	6,620	6,618	6,538	6,470	6,420	6,332	6,005	5,665	78,137	6,511
Cyprus TB and PD	Revenue - 2003 Load	34,318	33,731	32,910	32,577	32,122	31,601	30,444	29,415	28,622	27,560	25,992	24,419	363,711	30,309
Mohave 2	2002 kW Demand	-	-	-	-	13,579	-	-	-	-	11,570	-	-	25,149	2,096
Mohave 2	Loads 2003	-	-	-	-	21,304	-	35,037	29,166	38,625	15,590	-	-	139,722	11,644
Mohave 2	12 Month Rolling Avg	2,096	2,096	2,096	2,096	2,740	2,740	5,659	8,090	11,309	11,644	11,644	11,644	73,850	6,154
Mohave 2	Revenue - 2003 Load	10,161	10,186	10,170	10,238	13,293	13,081	26,351	36,779	50,416	50,680	50,398	50,189	331,942	27,662
Safford/Gila	2002 kW Demand	-	-	-	-	-	-	-	-	-	9,649	7,038	7,691	24,378	2,032
Safford/Gila	Loads 2003	7,344	7,793	7,344	8,119	13,281	15,178	16,014	14,974	15,245	9,794	7,144	7,806	130,036	10,836
Safford/Gila	12 Month Rolling Avg	2,644	3,293	3,905	4,582	5,688	6,953	8,288	9,535	10,806	10,818	10,827	10,836	88,174	7,348
Safford/Gila	Revenue - 2003 Load	12,817	16,005	18,950	22,382	27,600	33,200	38,589	43,352	48,175	47,087	46,862	46,710	401,728	33,477
Total	2002 kW Demand	259,949	255,476	228,349	264,660	354,063	359,156	377,206	367,083	336,812	270,499	219,117	256,655	3,549,025	295,752
Total	Loads 2003	227,326	246,798	233,791	241,243	377,915	416,091	468,093	455,578	411,003	363,220	241,090	273,026	3,955,174	329,598
Total	12 Month Rolling Avg	293,034	292,310	292,764	290,812	292,800	297,545	305,119	312,493	318,676	326,403	328,234	329,598	3,679,786	306,649
Total	Revenue - 2003 Load	1,420,722	1,420,722	1,420,722	1,420,722	1,420,722	1,420,722	1,420,722	1,420,722	1,420,722	1,420,722	1,420,722	1,420,722	17,048,663	1,420,722
Average	Per kW-month	$ 6.250	$ 5.757	$ 6.077	$ 5.889	$ 3.759	$ 3.414	$ 3.035	$ 3.119	$ 3.457	$ 3.911	$ 5.893	$ 5.204	$ 4.310	$ 4.310

* Load Ratios used in revenue allocation are based on 2002 and 2003 billing kW. Actual rolling 12-month average Load Ratio Shares will be used to allocate the Network Service Revenue Requirement.

Southwest Transmission Cooperative, Inc.
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Surrebuttal Schedule EEC-8

Calculation of Schedule 1: System Control and Load Dispatch Recommended Rates Through December 31, 2005

Costs: System Control and Load Dispatch	Southwest Adjusted 2003 TY	Staff Adjustments	Staff Adjusted 2003 TY
556 - Power Prod. Exp. - Maint. Syst Cntl & Load Disp	2,537,388	-	2,537,388
557 - Power Prod. Exp. - Maint. Other Expenses	3,946	-	3,946
561 - Transm Exp – Op. Load Disp	635	(9)	626
EMS payment from AEPCO	(306,624)	-	(306,624)
Total Cost - System Control and Load Dispatch	**2,235,345**	**(9)**	**2,235,336**

Generation Capacity	**Net kW Rate**
Apache Units (@SRSG)	585,300
Purchased Pwr (PNM & TECO)	29,667
Federal Hydro (CRSP & PD)	29,113
Total Generation Capacity	**644,080**
Annual Rate ($ / kW)	**$ 3.471**
Monthly Rate ($ / kW)	**$ 0.289**

Point-to-Point Schedule 1

Month		Present Rate	Recommended Rate	Present Revenue	Recommended Revenue
Jan	227,000	$ 0.4220	$ 0.2890	95,794	65,603
Feb	227,000	$ 0.4220	$ 0.2890	95,794	65,603
Mar	227,000	$ 0.4220	$ 0.2890	95,794	65,603
Apr	227,000	$ 0.4220	$ 0.2890	95,794	65,603
May	229,000	$ 0.4220	$ 0.2890	96,638	66,181
Jun	229,000	$ 0.4220	$ 0.2890	96,638	66,181
Jul	229,000	$ 0.4220	$ 0.2890	96,638	66,181
Aug	229,000	$ 0.4220	$ 0.2890	96,638	66,181
Sep	229,000	$ 0.4220	$ 0.2890	96,638	66,181
Oct	229,000	$ 0.4220	$ 0.2890	96,638	66,181
Nov	227,000	$ 0.4220	$ 0.2890	95,794	65,603
Dec	227,000	$ 0.4220	$ 0.2890	95,794	65,603
Total Schedule 1 Revenues from Point-to-Point Customers				1,154,592	**790,704**

Network Service Schedule 1

Month		Present Rate	Recommended Rate	Present Revenue	Recommended Revenue
Jan	227,326	$ 0.4220	$ 0.2890	95,932	65,697
Feb	246,798	$ 0.4220	$ 0.2890	104,149	71,325
Mar	233,791	$ 0.4220	$ 0.2890	98,660	67,566
Apr	241,243	$ 0.4220	$ 0.2890	101,805	69,719
May	377,915	$ 0.4220	$ 0.2890	159,480	109,217
Jun	416,091	$ 0.4220	$ 0.2890	175,590	120,250
Jul	468,093	$ 0.4220	$ 0.2890	197,535	135,279
Aug	455,578	$ 0.4220	$ 0.2890	192,254	131,662
Sep	411,003	$ 0.4220	$ 0.2890	173,443	118,780
Oct	363,220	$ 0.4220	$ 0.2890	153,279	104,971
Nov	241,090	$ 0.4220	$ 0.2890	101,740	69,675
Dec	273,026	$ 0.4220	$ 0.2890	115,217	78,905
Total Schedule 1 Revenues from Network Customers				1,669,083	**1,143,045**

Southwest Transmission Cooperative, Inc.
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Surrebuttal Schedule EEC-9

Calculation of Schedule 2: Cost of Reactive Power (VAR) Production
Recommended Rates Through December 31, 2005

Line No.	Power Factor	Gross Namplate KW	Power Factor Generator Nameplate	Weighted Power Factor
1	Steam Unit 1	77,400	0.85	10.9%
2	Steam Unit 2	195,000	0.85	27.4%
3	Steam Unit 3	195,000	0.85	27.4%
4	Gas Turbine 1	10,000	0.85	1.4%
5	Gas Turbine 2	20,000	0.90	3.0%
6	Gas Turbine 3	65,000	0.90	9.7%
7	Gas Turbine 4	42,000	0.85	5.9%
	Total Capacity	604,400		85.7%
8	**1 - Power Factor**			14.30%

		Account	Original Cost	Net Plant in Service
	AEPCO System Investment in Power Production Facilities			
9	Total Production Plant in Service		389,590,504	203,345,337
10	Turbogenerator Systems	314 & 344	55,169,579	26,798,200
11	Accessory Electric Equipment	315 & 345	19,941,398	9,686,381
	Separation of Production Plant Allocation to VAR Production			
12	Generator and Exciter Systems	(8) * (10)		3,831,291
13	Accessory Electric Equipment	(8) * (11)		1,384,845
14	Other Power Production Facilities	(9) - (12) - (13) * (0.25%)		495,323
15	Total Plant Allocated to VAR Production			5,711,459
16	TIER & Associated Required Rate of Return (AEPCO)		1.50	10.496%
17	Annualized Required Revenue Allocation to VAR Production			**$ 599,446**

	Schedule 2: Reactive Power (VAR) Production	Billing Unit	Demand kW	$/KW/year	$/kW/month
18	Network Service Rate	System 12 CP	557,598	$ 1.0751	$ 0.0900
19	Point-to-Point Rate	System 1 CP	697,093	$ 0.8599	$ 0.0720

Southwest Transmission Cooperative, Inc. Surrebuttal Schedule EEC-10
Docket No. E-04100A-04-0527
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Calculation of Schedule 4: Energy Imbalance
Recommended Rates Through December 31, 2005

Southwest Transmission Proposed Rate					
Costs: Energy Imbalance	**TY 2003**	**TY 2003**	**TY 2003**	**TY 2003**	**TY 2003**
Incremental Energy Costs	Southwest Per Books	Southwest Pro Forma Adjustments	Southwest Adjusted	Southwest Cost of Service: Energy	Southwest Schedule 4 Costs
Production Exp - Fuel - 501/547	62,295,417	(2,491,992)	59,803,425	57,819,080	57,819,080
Purchased Power Exp - 555	9,639,192	446,346	10,085,538	10,085,538	10,085,538
Production Exp - Transmission	8,036,486	-	8,036,486	77,291	77,291
Total	79,971,095	(2,045,646)	77,925,449	67,981,909	67,981,909
Total Energy Sales (kWh)					3,281,912,645
Southwest Transmission Proposed - Cost per kWh					$ 0.02071
Southwest Transmission Proposed - Cost per MWH					$ 20.71

Staff Recommended Rate			
Costs: Energy Imbalance	**TY 2003**	**TY 2003**	**TY 2003**
Incremental Energy Costs	Southwest Cost of Service: Energy	Staff Adjustments to Cost of Service: Energy	Staff Recommended Schedule 4 Costs
Production Exp - Fuel - 501/547	57,819,080	(1,030,873)	56,788,207
Purchased Power Exp - 555	10,085,538	-	10,085,538
Production Exp - Transmission	77,291	-	77,291
Total	67,981,909	(1,030,873)	66,951,036
Total Energy Sales (kWh)			3,281,912,645
Staff Recommended - Cost per kWh			$ 0.02040
Staff Recommended - Cost per MWH			$ 20.40

Southwest Transmission Cooperative, Inc.
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Surrebuttal Schedule EEC-11

Calculation of Schedule 3, 5, & 6
Recommended Rates Through December 31, 2005

Cost of Ancillary Services:
Regulation and Frequency Response, Operating Reserve - Spinning, and Operating Reserve - Supplemental

Apache Generation Units	SRSG Name Plate Rating	Production Plant	O&M Expenses	A&G Expenses	Tax Expenses	Depreciation Expenses	Required Return on Production Plant	Annual Revenue Requirement	Revenue Requirement per KW
Total to Allocate			25,358,928	9,589,717	3,346,839	7,539,289	21,779,757	67,614,530	
ST1	77,400	21,981,781	1,524,786	576,612	201,239	453,324	1,309,577	4,065,538	$ 52.53
ST2	185,000	154,434,564	10,712,492	4,051,030	1,413,821	3,184,858	9,200,526	28,562,727	$ 154.39
ST3	186,000	147,491,658	10,230,891	3,868,908	1,350,260	3,041,676	8,786,898	27,278,634	$ 146.66
IC1/GT1	10,400	1,843,357	127,866	48,354	16,876	38,015	109,819	340,930	$ 32.78
GT2	17,600	2,898,287	201,042	76,026	26,533	59,771	172,667	536,039	$ 30.46
GT3	66,500	8,359,793	579,885	219,289	76,532	172,401	498,039	1,546,147	$ 23.25
GT4	42,400	28,572,620	1,981,965	749,499	261,577	589,245	1,702,230	5,284,516	$ 124.63
Total	585,300	365,582,060	25,358,928	9,589,717	3,346,839	7,539,289	21,779,757	67,614,530	$ 115.52

Schedule 3
Regulation and Frequency Response

Apache Generation Units	SRSG Name Plate Rating	Revenue Requirement per KW	Annual Revenue Requirement
ST1	77,400	$ 52.53	4,065,538
ST2	185,000	$ 154.39	28,562,727
ST3	186,000	$ 146.66	27,278,634
Total	448,400		59,906,898
Annual Generation Capacity Rate		$	133.601
Monthly Generation Capacity Rate		$	11.133
Required Reserve Percentage			3.99%
Schedule 3 Monthly Rate ($/KW)		**$**	**0.4440**

Schedule 5
Operating Reserves - Spinning

Apache Generation Units	SRSG Name Plate Rating	Revenue Requirement per KW	Annual Revenue Requirement
ST2	185,000	154	28,562,727
ST3	186,000	147	27,278,634
Total	371,000		55,841,360
Annual Generation Capacity Rate		$	150.516
Monthly Generation Capacity Rate		$	12.543
Required Reserve Percentage			5.35%
Schedule 5 Monthly Rate ($/KW)		**$**	**0.6710**

Schedule 6
Operating Reserves - Supplemental

Apache Generation Units	SRSG Name Plate Rating	Revenue Requirement per KW	Annual Revenue Requirement
GT2	17,600	$ 30.46	536,039
GT4	42,400	$ 124.63	5,284,516
Total	60,000		5,820,555
Annual Generation Capacity Rate		$	97.009
Monthly Generation Capacity Rate		$	8.084
Required Reserve Percentage			5.36%
Schedule 6 Monthly Rate ($/KW)		**$**	**0.4330**

Southwest Transmission Cooperative, Inc.
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Comparison of Billing Units
Recommended Rates Effective January 1, 2006

	Actual 2003 Test Year Billing Units Including MW&E 60 MW			Adjusted 2003 Test Year Billing Units Excluding MW&E 60 MW		
Month	**Network kW**	**PTP kW**	**Total kW**	**Network kW**	**PTP kW**	**Total kW**
Jan	227,326	227,000	454,326	227,326	167,000	394,326
Feb	246,798	227,000	473,798	246,798	167,000	413,798
Mar	233,791	227,000	460,791	233,791	167,000	400,791
Apr	241,243	227,000	468,243	241,243	167,000	408,243
May	377,915	229,000	606,915	377,915	169,000	546,915
Jun	416,091	229,000	645,091	416,091	169,000	585,091
Jul	468,093	229,000	**697,093**	468,093	169,000	**637,093**
Aug	455,578	229,000	684,578	455,578	169,000	624,578
Sep	411,003	229,000	640,003	411,003	169,000	580,003
Oct	363,220	229,000	592,220	363,220	169,000	532,220
Nov	241,090	227,000	468,090	241,090	167,000	408,090
Dec	273,026	227,000	500,026	273,026	167,000	440,026
1 CP	468,093	229,000	697,093	468,093	169,000	637,093
4 CP	437,691	229,000	666,691	437,691	169,000	606,691
12 CP	329,598	228,000	557,598	329,598	168,000	497,598

Calculation of the Point-to-Point Rate
Recommended Rates Effective January 1, 2006

Total Revenue Requirement = O&M + Depr&Amort + Taxes + Operating Margin		
O&M		16,237,302
Depreciation & Amortization		4,144,985
Taxes		2,285,845
Operating Margin		6,146,732
Total Revenue Requirement		**28,814,864**
Less Other Operating Revenues		
Direct Assignment		515,580
Regulatory Asset Charge		-
Other Reveues		413,318
Special Contracts		673,342
Ancillary Service (Schedules 2-6)		-
Total Other Operating Revenues		**1,602,240**
Transmission Revenue Requirement (including Schedule 1)		**27,212,624**
Schedule 1 Revenues	**$ / kW**	
Schedule 1 - PtP Revenue	0.289	582,624
Schedule 1 - Network Services Revenue	0.289	1,143,045
Total Schedule 1 Revenues		1,725,669
Total Transmission Revenue Requirement		**25,486,955**

Point to Point Transmission Serive (1 CP method)

	Revenue Requirement	TY 2003 1 CP (kW)	Annual Rate ($/kW)	Monthly Rate ($/kW)
1 CP Rate - Standard	25,486,955	637,093	$40.01	$3.334

Point-to-Point Service	Standard Ave Montly kW	Standard PTP Rate	Standard PTP Revenute
Jan	163,000	$3.334	$543,442
Feb	163,000	$3.334	$543,442
Mar	163,000	$3.334	$543,442
Apr	163,000	$3.334	$543,442
May	163,000	$3.334	$543,442
Jun	163,000	$3.334	$543,442
Jul	163,000	$3.334	$543,442
Aug	163,000	$3.334	$543,442
Sep	163,000	$3.334	$543,442
Oct	163,000	$3.334	$543,442
Nov	163,000	$3.334	$543,442
Dec	163,000	$3.334	$543,442
Total			**$6,521,304**

Southwest Transmission Cooperative, Inc.
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Calculation of the Discount to the Point-to-Point Rate for the Town of Thatcher
Recommended Rates Effective January 1, 2006

Total Transmission Revenue Requirement	**25,486,955**
Discount for Town of Thatcher - WAPA Wheeling Expenses	
(Remove WAPA Wheeling Expenses from Total Transmission Revenue Requirement)	
WAPA Wheeling Costs $3,484,188	3,484,188
Town of Thatcher Transmission Revenue Requirement	**22,002,767**

Point to Point Transmission Serive (1 CP method)

	Revenue Requirement	TY 2003 1 CP (kW)	Annual Rate ($/kW)	Monthly Discount	Monthly Rate ($/kW)
1 CP Rate - Thatcher Discount	22,002,767	637,093	$34.54	$0.456	$2.878

Point-to-Point Service	Thatcher Ave Monthly kW	Thatcher Discount PTP Rate	Thatcher Discount PTP Revenue
Jan	4,000	$2.878	$11,512
Feb	4,000	$2.878	$11,512
Mar	4,000	$2.878	$11,512
Apr	4,000	$2.878	$11,512
May	6,000	$2.878	$17,268
Jun	6,000	$2.878	$17,268
Jul	6,000	$2.878	$17,268
Aug	6,000	$2.878	$17,268
Sep	6,000	$2.878	$17,268
Oct	6,000	$2.878	$17,268
Nov	4,000	$2.878	$11,512
Dec	4,000	$2.878	$11,512
Total - Town of Thatcher			**$172,680**

Southwest Transmission Cooperative, Inc.
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Calculation of the Point-to-Point Revenues
Recommended Rates Effective January 1, 2006

Point to Point Transmission Serive (1 CP method)

	Revenue Requirement	TY 2003 1 CP (kW)	Annual Rate ($/kW)	Monthly Discount	Monthly Rate ($/kW)
1 CP Rate - Standard	25,486,955	637,093	$40.01	$0.000	$3.334
1 CP Rate - Thatcher Discount	22,002,767	637,093	$34.54	$0.456	$2.878
1 CP Rate - MW&E Greenlee Discount	-	-	-	-	-

Point-to-Point Service	Standard Ave Monthly kW	Thatcher Ave Monthly kW	MW&E Ave Monthly kW	Standard PTP Rate	Thatcher Discount PTP Rate	MW&E Discount PTP Rate
Jan	163,000	4,000	0	$3.334	$2.878	$0.000
Feb	163,000	4,000	0	$3.334	$2.878	$0.000
Mar	163,000	4,000	0	$3.334	$2.878	$0.000
Apr	163,000	4,000	0	$3.334	$2.878	$0.000
May	163,000	6,000	0	$3.334	$2.878	$0.000
Jun	163,000	6,000	0	$3.334	$2.878	$0.000
Jul	163,000	6,000	0	$3.334	$2.878	$0.000
Aug	163,000	6,000	0	$3.334	$2.878	$0.000
Sep	163,000	6,000	0	$3.334	$2.878	$0.000
Oct	163,000	6,000	0	$3.334	$2.878	$0.000
Nov	163,000	4,000	0	$3.334	$2.878	$0.000
Dec	163,000	4,000	0	$3.334	$2.878	$0.000

Point-to-Point Service	Standard PTP Revenute	Thatcher Discount PTP Revenue	MW&E Discount PTP Revenue	Total PTP Annual Revenues
Jan	$543,442	$11,512	$0	$554,954
Feb	$543,442	$11,512	$0	$554,954
Mar	$543,442	$11,512	$0	$554,954
Apr	$543,442	$11,512	$0	$554,954
May	$543,442	$17,268	$0	$560,710
Jun	$543,442	$17,268	$0	$560,710
Jul	$543,442	$17,268	$0	$560,710
Aug	$543,442	$17,268	$0	$560,710
Sep	$543,442	$17,268	$0	$560,710
Oct	$543,442	$17,268	$0	$560,710
Nov	$543,442	$11,512	$0	$554,954
Dec	$543,442	$11,512	$0	$554,954
Total Revenues	$6,521,304	$172,680	$0	$6,693,984

Point-to-Point Revenue Total $6,693,984

Southwest Transmission Cooperative, Inc. Surrebuttal Schedule EEC-16
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Calculation of the Network Service Revenue Requirement
Recommended Rates Effective January 1, 2006

Total Revenue Requirement = O&M + Depr&Amort + Taxes + Operating Margin		
O&M		16,237,302
Depr&Amort		4,144,985
Taxes		2,285,845
Operating Margin		6,146,732
Total Revenue Requirement		**28,814,864**
Less Other Operating Revenues		
Direct Assignment		515,580
Regulatory Asset Charge		-
Other Reveues		413,318
Special Contracts		673,342
Ancillary Service (Schedules 2-6)		-
Total Other Operating Revenues		**1,602,240**
Transmission Revenue Requirement (including Schedule 1)		**27,212,624**
Schedule 1 Revenues	**$ / KW**	
Schedule 1 - PtP Revenue	0.289	582,624
Schedule 1 - Network Services Revenue	0.289	1,143,045
Total Schedule 1 Revenues		1,725,669
Total Transmission Revenue Requirement		**25,486,955**
Less: Point-to-Point Revenue Total		**6,693,984**
Network Services Annual Revenue Requirement		**18,792,971**
Network Services Monthly Revenue Requirement		**1,566,081**

Network Services Revenue Requirement	2003 TY Billing Demand kW	Recommended Revenue Requirement Network Service	Average Network Service $/kW
Annual		**18,792,971**	**$4.751**
January	227,326	$1,566,081	$6.889
February	246,798	$1,566,081	$6.346
March	233,791	$1,566,081	$6.699
April	241,243	$1,566,081	$6.492
May	377,915	$1,566,081	$4.144
June	416,091	$1,566,081	$3.764
July	468,093	$1,566,081	$3.346
August	455,578	$1,566,081	$3.438
September	411,003	$1,566,081	$3.810
October	363,220	$1,566,081	$4.312
November	241,090	$1,566,081	$6.496
December	273,026	$1,566,081	$5.736

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Estimated Allocation of the Network Service Revenue Requirement*
Recommended Rates Effective January 1, 2006

NETWORK CUSTOMERS		January	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total 2003	Average
Anza	2002 kW Demand	6,432	6,084	5,472	5,496	6,660	7,068	8,628	8,400	7,812	5,112	6,324	6,912	80,400	6,700
Anza	Loads 2003	5,436	5,556	6,012	5,496	7,452	7,920	9,516	9,264	7,644	6,708	5,424	6,036	82,464	6,872
Anza	12 Month Rolling Avg	6,617	6,573	6,618	6,618	6,684	6,755	6,829	6,901	6,887	7,020	6,945	6,872	81,319	6,777
Anza	Revenue - 2003 Load	35,364	35,215	35,402	35,639	35,750	35,554	35,051	34,585	33,845	33,682	33,136	32,652	415,876	34,656
Duncan	2002 kW Demand	3,320	2,360	3,440	3,780	5,320	6,040	5,240	5,340	4,840	2,900	3,080	3,460	49,120	4,093
Duncan	Loads 2003	3,000	3,280	3,280	3,420	4,780	5,400	5,180	4,820	5,380	4,600	3,300	3,760	50,200	4,183
Duncan	12 Month Rolling Avg	4,067	4,143	4,130	4,100	4,055	4,002	3,997	3,953	3,998	4,140	4,158	4,183	48,927	4,077
Duncan	Revenue - 2003 Load	21,734	22,198	22,093	22,079	21,689	21,062	20,514	19,812	19,649	19,864	19,840	19,877	250,411	20,868
Graham	2002 kW Demand	14,758	15,023	15,662	20,461	27,751	33,126	33,349	30,972	28,798	16,583	14,149	16,503	267,135	22,261
Graham	Loads 2003	13,710	14,481	15,790	17,075	23,316	31,629	33,111	33,096	29,452	22,775	15,313	14,738	264,486	22,041
Graham	12 Month Rolling Avg	22,174	22,129	22,139	21,857	21,488	21,363	21,343	21,520	21,575	22,091	22,188	22,041	261,906	21,826
Graham	Revenue - 2003 Load	118,506	118,557	118,430	117,706	114,930	112,440	109,548	107,849	106,025	105,991	105,862	104,725	1,340,569	111,714
Mohave 1	2002 kW Demand	71,793	71,893	62,190	94,674	110,200	99,000	116,000	115,000	96,000	79,000	60,296	64,007	1,040,053	86,671
Mohave 1	Loads 2003	60,706	68,839	61,639	64,778	116,000	137,930	130,000	129,000	109,000	112,000	65,082	73,050	1,128,024	94,002
Mohave 1	12 Month Rolling Avg	85,747	85,493	85,447	82,955	83,439	86,683	87,850	89,016	90,100	92,850	93,248	94,002	1,056,829	88,069
Mohave 1	Revenue - 2003 Load	458,265	458,035	457,080	446,731	446,283	456,242	450,905	446,111	442,780	445,493	444,910	446,650	5,399,486	449,957
Sulphur Springs	2002 kW Demand	94,849	93,072	82,413	71,220	103,544	110,561	112,009	107,663	102,241	76,651	75,788	92,659	1,122,670	93,556
Sulphur Springs	Loads 2003	82,360	84,958	82,242	83,467	101,093	112,464	123,813	121,214	108,324	101,850	83,848	96,867	1,182,500	98,542
Sulphur Springs	12 Month Rolling Avg	92,515	91,839	91,825	92,845	92,641	92,800	93,783	94,913	95,419	97,519	98,191	98,542	1,132,832	94,403
Sulphur Springs	Revenue - 2003 Load	494,435	492,036	491,197	499,990	495,503	488,436	481,361	475,660	468,923	467,898	468,493	468,220	5,792,153	482,679
Trico	2002 kW Demand	60,797	59,164	51,292	61,409	79,649	96,441	94,660	92,968	90,421	62,274	45,742	58,683	853,500	71,125
Trico	Loads 2003	48,450	55,671	51,504	52,628	83,909	98,670	109,062	108,124	91,233	84,203	58,199	68,109	909,762	75,814
Trico	12 Month Rolling Avg	70,096	69,805	69,823	69,091	69,446	69,632	70,832	72,095	72,163	73,990	75,028	75,814	857,813	71,484
Trico	Revenue - 2003 Load	374,620	373,987	373,502	372,068	371,441	366,496	363,558	361,308	354,631	355,004	357,977	360,227	4,384,819	365,402
AEPCO Bundled	2002 kW Demand	8,000	7,880	7,880	7,620	7,360	6,920	7,320	6,740	6,700	6,760	6,700	6,740	86,620	7,218
Power Sales using	Loads 2003	6,320	6,220	5,980	6,260	6,780	6,900	6,360	5,920	6,100	5,700	2,780	2,660	67,980	5,665
Network Service	12 Month Rolling Avg	7,078	6,940	6,782	6,668	6,620	6,618	6,538	6,470	6,420	6,332	6,005	5,665	78,137	6,511
Cyprus TB and PD	Revenue - 2003 Load	37,829	37,182	36,277	35,910	35,408	34,835	33,559	32,425	31,550	30,379	28,651	26,917	400,923	33,410
Mohave 2	2002 kW Demand	-	-	-	-	13,579	-	-	-	-	11,570	-	-	25,149	2,096
Mohave 2	Loads 2003	-	-	-	-	21,304	-	35,037	29,166	38,625	15,590	-	-	139,722	11,644
Mohave 2	12 Month Rolling Avg	2,096	2,096	2,096	2,096	2,740	2,740	5,659	8,090	11,309	11,644	11,644	11,644	73,850	6,154
Mohave 2	Revenue - 2003 Load	11,200	11,228	11,211	11,286	14,653	14,419	29,047	40,542	55,574	55,866	55,554	55,324	365,904	30,492
Safford/Gila	2002 kW Demand	-	-	-	-	-	-	-	-	-	9,649	7,038	7,691	24,378	2,032
Safford/Gila	Loads 2003	7,344	7,793	7,344	8,119	13,281	15,178	16,014	14,974	15,245	9,794	7,144	7,806	130,036	10,836
Safford/Gila	12 Month Rolling Avg	2,644	3,293	3,905	4,582	5,688	6,953	8,288	9,535	10,806	10,818	10,827	10,836	88,174	7,348
Safford/Gila	Revenue - 2003 Load	14,128	17,642	20,889	24,672	30,424	36,596	42,538	47,787	53,104	51,904	51,657	51,489	442,830	36,903
Total	2002 kW Demand	259,949	255,476	228,349	264,660	354,063	359,156	377,206	367,083	336,812	270,499	219,117	256,655	3,549,025	295,752
Total	Loads 2003	227,326	246,798	233,791	241,243	377,915	416,091	468,093	455,578	411,003	363,220	241,090	273,026	3,955,174	329,598
Total	12 Month Rolling Avg	293,034	292,310	292,764	290,812	292,800	297,545	305,119	312,493	318,676	326,403	328,234	329,598	3,679,786	306,649
Total	Revenue - 2003 Load	1,566,081	1,566,081	1,566,081	1,566,081	1,566,081	1,566,081	1,566,081	1,566,081	1,566,081	1,566,081	1,566,081	1,566,081	18,792,971	1,566,081
Average	*Per kW-month*	$ 6.889	$ 6.346	$ 6.699	$ 6.492	$ 4.144	$ 3.764	$ 3.346	$ 3.438	$ 3.810	$ 4.312	$ 6.496	$ 5.736	$ 4.751	$ 4.751

* Load Ratios used in revenue allocation are based on 2002 and 2003 billing kW. Actual rolling 12-month average Load Ratio Shares will be used to allocate the Network Service Revenue Requirement.

Southwest Transmission Cooperative, Inc.
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Test Year Ended December 31, 2003

Surrebuttal Schedule EEC-18

Calculation of Schedule 1: System Control and Load Dispatch
Recommended Rates Effective January 1, 2006

Costs: System Control and Load Dispatch	Southwest Adjusted 2003 TY	Staff Adjustments	*Staff* Adjusted 2003 TY
556 - Power Prod. Exp. - Maint. Syst Cntl & Load Disp	2,537,388	-	2,537,388
557 - Power Prod. Exp. - Maint. Other Expenses	3,946	-	3,946
561 - Transm Exp – Op. Load Disp	635	(9)	626
EMS payment from AEPCO	(306,624)	-	(306,624)
Total Cost - System Control and Load Dispatch	**2,235,345**	**(9)**	**2,235,336**

Generation Capacity	Net kW Rate
Apache Units (@SRSG)	585,300
Purchased Pwr (PNM & TECO)	29,667
Federal Hydro (CRSP & PD)	29,113
Total Generation Capacity	***644,080***

Annual Rate ($ / kW)	$	3.471
Monthly Rate ($ / kW)	$	0.289

Point-to-Point Schedule 1

Month			Present Rate		Recommended Rate	Present Revenue	Recommended Revenue
Jan	167,000	$	0.4220	$	0.2890	70,474	48,263
Feb	167,000	$	0.4220	$	0.2890	70,474	48,263
Mar	167,000	$	0.4220	$	0.2890	70,474	48,263
Apr	167,000	$	0.4220	$	0.2890	70,474	48,263
May	169,000	$	0.4220	$	0.2890	71,318	48,841
Jun	169,000	$	0.4220	$	0.2890	71,318	48,841
Jul	169,000	$	0.4220	$	0.2890	71,318	48,841
Aug	169,000	$	0.4220	$	0.2890	71,318	48,841
Sep	169,000	$	0.4220	$	0.2890	71,318	48,841
Oct	169,000	$	0.4220	$	0.2890	71,318	48,841
Nov	167,000	$	0.4220	$	0.2890	70,474	48,263
Dec	167,000	$	0.4220	$	0.2890	70,474	48,263
Total Schedule 1 Revenues from Point-to-Point Customers						850,752	**582,624**

Network Service Schedule 1

Month			Present Rate		Recommended Rate	Present Revenue	Recommended Revenue
Jan	227,326	$	0.4220	$	0.2890	95,932	65,697
Feb	246,798	$	0.4220	$	0.2890	104,149	71,325
Mar	233,791	$	0.4220	$	0.2890	98,660	67,566
Apr	241,243	$	0.4220	$	0.2890	101,805	69,719
May	377,915	$	0.4220	$	0.2890	159,480	109,217
Jun	416,091	$	0.4220	$	0.2890	175,590	120,250
Jul	468,093	$	0.4220	$	0.2890	197,535	135,279
Aug	455,578	$	0.4220	$	0.2890	192,254	131,662
Sep	411,003	$	0.4220	$	0.2890	173,443	118,780
Oct	363,220	$	0.4220	$	0.2890	153,279	104,971
Nov	241,090	$	0.4220	$	0.2890	101,740	69,675
Dec	273,026	$	0.4220	$	0.2890	115,217	78,905
Total Schedule 1 Revenues from Network Customers						1,669,083	**1,143,045**

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
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Calculation of Schedule 2: Cost of Reactive Power (VAR) Production
Recommended Rates Effective January 1, 2006

Line No.	Power Factor	Gross Namplate KW	Power Factor Generator Nameplate	Weighted Power Factor
1	Steam Unit 1	77,400	0.85	10.9%
2	Steam Unit 2	195,000	0.85	27.4%
3	Steam Unit 3	195,000	0.85	27.4%
4	Gas Turbine 1	10,000	0.85	1.4%
5	Gas Turbine 2	20,000	0.90	3.0%
6	Gas Turbine 3	65,000	0.90	9.7%
7	Gas Turbine 4	42,000	0.85	5.9%
	Total Capacity	604,400		85.7%
8	**1 - Power Factor**			14.30%

Line No.		Account	Original Cost	Net Plant in Service
	AEPCO System Investment in Power Production Facilities			
9	Total Production Plant in Service		389,590,504	203,345,337
10	Turbogenerator Systems	314 & 344	55,169,579	26,798,200
11	Accessory Electric Equipment	315 & 345	19,941,398	9,686,381
	Separation of Production Plant Allocation to VAR Production			
12	Generator and Exciter Systems	(8) * (10)		3,831,291
13	Accessory Electric Equipment	(8) * (11)		1,384,845
14	Other Power Production Facilities	(9) - (12) - (13) * (0.25%)		495,323
15	Total Plant Allocated to VAR Production			5,711,459
16	TIER & Associated Required Rate of Return (AEPCO)		1.50	10.496%
17	Annualized Required Revenue Allocation to VAR Production			**$ 599,446**

Line No.	**Schedule 2: Reactive Power (VAR) Production**	**Billing Unit**	**Demand kW**	**$/KW/year**	**$/kW/month**
18	Network Service Rate	System 12 CP	497,598	$ 1.2047	$ 0.1000
19	Point-to-Point Rate	System 1 CP	637,093	$ 0.9409	$ 0.0780

Southwest Transmission Cooperative, Inc. Surrebuttal Schedule EEC-20
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Calculation of Schedule 4: Energy Imbalance
Recommended Rates Effective January 1, 2006

Southwest Transmission Proposed Rate					
Costs: Energy Imbalance	**TY 2003**	**TY 2003**	**TY 2003**	**TY 2003**	**TY 2003**
Incremental Energy Costs	Southwest Per Books	Southwest Pro Forma Adjustments	Southwest Adjusted	Southwest Cost of Service: Energy	Southwest Schedule 4 Costs
Production Exp - Fuel - 501/547	62,295,417	(2,491,992)	59,803,425	57,819,080	57,819,080
Purchased Power Exp - 555	9,639,192	446,346	10,085,538	10,085,538	10,085,538
Production Exp - Transmission	8,036,486	-	8,036,486	77,291	77,291
Total	79,971,095	(2,045,646)	77,925,449	67,981,909	67,981,909
Total Energy Sales (kWh)					3,281,912,645
Southwest Transmission Proposed - Cost per kWh					$ 0.02071
Southwest Transmission Proposed - Cost per MWH					$ 20.71

Staff Recommended Rate			
Costs: Energy Imbalance	**TY 2003**	**TY 2003**	**TY 2003**
Incremental Energy Costs	Southwest Cost of Service: Energy	Staff Adjustments to Cost of Service: Energy	Staff Recommended Schedule 4 Costs
Production Exp - Fuel - 501/547	57,819,080	(1,030,873)	56,788,207
Purchased Power Exp - 555	10,085,538	-	10,085,538
Production Exp - Transmission	77,291	-	77,291
Total	67,981,909	(1,030,873)	66,951,036
Total Energy Sales (kWh)			3,281,912,645
Staff Recommended - Cost per kWh			$ 0.02040
Staff Recommended - Cost per MWH			$ 20.40

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Surrebuttal Schedule EEC-21

Calculation of Schedule 3, 5, & 6
Recommended Rates Effective January 1, 2006

Cost of Ancillary Services:
Regulation and Frequency Response, Operating Reserve - Spinning, and Operating Reserve - Supplemental

Apache Generation Units	SRSG Name Plate Rating	Production Plant	O&M Expenses	A&G Expenses	Tax Expenses	Depreciation Expenses	Required Return on Production Plant	Annual Revenue Requirement	Revenue Requirement per KW
Total to Allocate			25,358,928	9,589,717	3,346,839	7,539,289	21,779,757	67,614,530	
ST1	77,400	21,981,781	1,524,786	576,612	201,239	453,324	1,309,577	4,065,538	$ 52.53
ST2	185,000	154,434,564	10,712,492	4,051,030	1,413,821	3,184,858	9,200,526	28,562,727	$ 154.39
ST3	186,000	147,491,658	10,230,891	3,868,908	1,350,260	3,041,676	8,786,898	27,278,634	$ 146.66
IC1/GT1	10,400	1,843,357	127,866	48,354	16,876	38,015	109,819	340,930	$ 32.78
GT2	17,600	2,898,287	201,042	76,026	26,533	59,771	172,667	536,039	$ 30.46
GT3	66,500	8,359,793	579,885	219,289	76,532	172,401	498,039	1,546,147	$ 23.25
GT4	42,400	28,572,620	1,981,965	749,499	261,577	589,245	1,702,230	5,284,516	$ 124.63
Total	585,300	365,582,060	25,358,928	9,589,717	3,346,839	7,539,289	21,779,757	67,614,530	$ 115.52

Schedule 3
Regulation and Frequency Response

Apache Generation Units	SRSG Name Plate Rating	Revenue Requirement per KW	Annual Revenue Requirement
ST1	77,400	$ 52.53	4,065,538
ST2	185,000	$ 154.39	28,562,727
ST3	186,000	$ 146.66	27,278,634
Total	448,400		59,906,898

Annual Generation Capacity Rate	$	133.601
Monthly Generation Capacity Rate	$	11.133
Required Reserve Percentage		3.99%
Schedule 3 Monthly Rate ($/KW)	**$**	**0.4440**

Schedule 5
Operating Reserves - Spinning

Apache Generation Units	SRSG Name Plate Rating	Revenue Requirement per KW	Annual Revenue Requirement
ST2	185,000	154	28,562,727
ST3	186,000	147	27,278,634
Total	371,000		55,841,360

Annual Generation Capacity Rate	$	150.516
Monthly Generation Capacity Rate	$	12.543
Required Reserve Percentage		5.35%
Schedule 5 Monthly Rate ($/KW)	**$**	**0.6710**

Schedule 6
Operating Reserves - Supplemental

Apache Generation Units	SRSG Name Plate Rating	Revenue Requirement per KW	Annual Revenue Requirement
GT2	17,600	$ 30.46	536,039
GT4	42,400	$ 124.63	5,284,516
Total	60,000		5,820,555

Annual Generation Capacity Rate	$	97.009
Monthly Generation Capacity Rate	$	8.084
Required Reserve Percentage		5.36%
Schedule 6 Monthly Rate ($/KW)	**$**	**0.4330**